



**Commonwealth of Kentucky  
Energy and Environment Cabinet  
Department for Environmental Protection  
Division for Air Quality**

**Revised Statement of Basis**

**Proposed Title V Permit, No. V-05-070 R3**

**East Kentucky Power Cooperative, Inc.  
J. K. Smith Generating Station**

**Trapp, KY**

**Source I.D. #: 21-049-00027**

**Source A.I. #: 808**

**Activity I.D. #: APE20080002**

**Reviewer: Combustion Section  
Modeling and Toxics Reviewed By: Air Toxics Section**

**Revised April 9, 2010**

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1. APPLICATION SUMMARY

On April 3, 2008, East Kentucky Power Cooperative, Inc. (EKPC) filed an application to construct two new coal-fired, circulating fluidized bed (CFB) boilers, and associated material handling and storage facilities for coal, limestone, lime, and ash, along with cooling towers and paved haul roads, at its existing J.K. Smith Generating Station (J.K. Smith). The application included an Acid Rain Permit Application and Clean Air Interstate Rule (CAIR) Permit Application. An addendum was filed on June 11, 2008.

On June 5, 2008, October 14, 2008, and January 9, 2009, the Division requested additional information. Responses were filed on July 31, 2008, November 14, 2008, and February 12, 2009. Comments were filed by the Sierra Club on February 20, 2009 related to the air modeling analysis.

On May 22, 2009, EKPC filed a response to the Sierra Club's February 20, 2009 comments, which included revised modeling and responses to issues raised at a meeting held on April 9, 2009 between representatives for the Division and EKPC. Additional clarification was provided by e-mail dated April 22-23 and by letters dated June 17, 2009, June 26, 2009, July 7, 2009, September 11, 2009, and October 14, 2009.

Effective September 14, 2009, 401 KAR 51:017 was modified to require the construction of major sources emitting more than 100 tons per year of nitrogen oxides (NO<sub>x</sub>) or modifications at a major source with the potential to emit more than 40 tons per year of NO<sub>x</sub> to conduct an ambient air quality analysis for ozone.

On September 29, 2009, EKPC filed an Ozone Ambient Impact Analysis and a request for waiver from pre-construction monitoring requirements. On October 12, 2009, the Division provided a response and requested clarifications regarding both the waiver request and ozone analysis. EKPC provided a response on October 22, 2009. A letter was issued on October 23, 2009, granting the waiver and stating the Division's concurrence that the emissions from the J.K. Smith project will not adversely impact the National Ambient Air Quality Standard for ozone in Clark County. A completeness letter was issued on November 19, 2009.

On December 2, 2009, the Division received a letter dated November 24, 2009 from Patrick H. Reed, Superintendent, Mammoth Cave National Park. The letter stated that:

*"The results show that the Class I increment significant impact levels will not be exceeded at Mammoth Cave NP. The AQRV analysis shows nitrogen and sulfur deposition concentrations will be below the deposition analysis thresholds (0.01 kg/ha/yr) at Mammoth Cave NP and the emissions will not cause adverse visibility impacts at the park. Therefore, we do not have concerns with the proposed modifications, addition of the two CTs and two CFBs at the J.K. Smith facility."*

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A letter from EKPC dated December 9, 2009 was received on December 10, 2009. That letter provided a corrected Table 5-2 of the Air Toxics Analysis that was included in the Revised Class II Modeling report dated May 22, 2009.

## 2. SOURCE SUMMARY

J.K. Smith is located in Clark County, Kentucky, 21 miles southeast of the city of Lexington, 8 miles south-southeast of the city of Winchester, and one mile west of the community of Trapp, Kentucky. Clark County is classified as attainment or unclassifiable for all pollutants. The proposed project will constitute a major modification pursuant to the Title V operating permit provisions in 401 KAR 52:020, and the magnitude of the increased emissions are such that the provisions of 401 KAR 51:017, Prevention of significant deterioration of air quality (PSD), apply.

Existing emission units consist of seven simple cycle combustion turbines that serve as peaking units, and operate pursuant to an existing Title V renewal permit, V-05-070, issued on August 1, 2006 and revised on November 14, 2007 (V-05-070 R1). On February 19, 2008, EKPC filed an application to add two GE LMS 100 natural gas-fired combustion turbines at the J. K. Smith site. The combustion turbine application and the CFB application that was filed on April 3, 2008 are considered one project for PSD purposes, and the air modeling reflects the impact of both applications. However, because combustion turbines and coal-fired boilers are significantly different from both a technical and air impact perspective, the Division processed them as two separate permit revisions. On October 24, 2008, the final revised permit V-05-070 R2 was issued, incorporating the new combustion turbines. This permit revision (V-05-070 R3) involves only the CFB boilers and associated facilities (Emission Units 11-19).

## 3. PROJECT SUMMARY

EKPC is proposing to construct the two CFB boilers in two different phases. EKPC indicated in their application that the first CFB will be constructed in phase one, with construction expected to commence in 2010. This phase will include CFB1, cooling tower for CFB1, and all the material handling facilities necessary for both CFB1 and CFB2. Phase two is expected to commence by August 1, 2013 and will consist of CFB2 and its associated cooling tower. Both phases are addressed in the application, but EKPC will be required to submit an updated BACT analysis no later than 18 months prior to commencing construction of CFB2.

In a CFB boiler, combustion occurs when coal, together with ash, and in this case, limestone, are suspended through the action of primary combustion air distributed below the combustion floor. EKPC is designing the proposed CFB boilers to use run of mine bituminous coal and coal waste, with the design fuel consisting of a blend of bituminous coal and locally available waste coal. The limestone, in conjunction with a fresh lime add-on flash dryer absorber (FDA) system will be used to control SO<sub>2</sub> emissions. Selective Non-Catalytic Reduction (SNCR) is being proposed to control NO<sub>x</sub>. Particulate matter emissions will be controlled by fabric filter. Emissions from the CFBs will be exhausted through separate stacks.

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The steam turbine generator set includes turbines designed to deliver 2400 psig and 1000°F inlet conditions and a 300 MVA generator. Both turbines and boilers will be enclosed. Equipment will be cooled by closed systems and ultimate heat rejection will be by mechanical draft cooling towers.

Coal will be delivered via truck and rail. The coal will be conveyed from the unloading areas via enclosed conveying equipment to two new coal piles. An enclosed conveying system will transfer coal from the coal pile to a new coal crusher house. The coal crusher house will provide processing and crushing of the coal to the desired specification for combustion. New coal silos within the boiler buildings will provide for storage of the coal prior to combustion in the new CFB boilers.

Lime and limestone will be delivered to the site by truck and stored. Limestone will be conveyed via an underground feeder into the boiler building, where it will be crushed then stored in silos prior to injection into the boilers. Fresh lime used by the dry scrubber system will be stored in a separate silo.

Ash handling systems will include conveyors for moving bed ash to two transfer silos where it will be stored dry to be loaded onto trucks for disposal. Fly ash will also be collected from the baghouses and economizers by means of a pneumatic system, then consolidated for transport and removal.

#### 4. APPLICABLE REGULATIONS

This section presents a discussion on the air quality regulations applicable to this project.

##### 4.1 Prevention of Significant Deterioration of Air Quality

401 KAR 51:017, Prevention of Significant Deterioration of air quality (PSD), applies to the construction of a new major stationary source that commences construction after September 22, 1982, and locates in an area designated attainment or unclassifiable under 42. U.S.C. 7407(d)(1)(A)(ii) and (iii). J.K. Smith is a "Major stationary source" as defined in 401 KAR 51:001/51:001E, Section 1 for the PSD program because it is a fossil fuel-fired steam electric plant of more than 250 MMBtu per hour heat input and will emit, or has the potential to emit, 100 tons per year or more of a regulated NSR pollutant. Pursuant to 401 KAR 51:010, Attainment status designations, Clark County is listed as "Cannot be Classified" or "Better Than Standards" for total suspended particulates, sulfur dioxide, carbon monoxide, ozone, and nitrogen oxides.

The following table, reproduced from data in Table 3-1 of the application, summarizes the maximum potential to emit (PTE) in tons per year (tpy) of both the CT project and the CFB project:

Table 4-1 Maximum Potential to Emit and PSD Applicability

Pollutant	2-CT's PTE (tpy)	2-CFB's PTE (tpy)	Total (tpy)	PSD Threshold	PSD Triggered
PM/PM <sub>10</sub> /PM <sub>2.5</sub>	40	365	405	25/15	Yes
SO <sub>2</sub>	0.4	1991	1991	40	Yes
NO <sub>x</sub>	67	1858	1925	40	Yes
CO	49	2655	2704	100	Yes
VOC(Ozone)	15	53	68	40	Yes
H <sub>2</sub> SO <sub>4</sub>	0.02	133	133	7	Yes
Fluorides	0	1.2	1.2	3	No
Pb	0	0.17	0.17	0.6	No
H <sub>2</sub> S	0	0	0	10	No
Reduced S	0	0	0	10	No

Note: May not total correctly due to rounding. Some of the potential to emit numbers have been revised (generally reduced) after the application was filed. However, the purpose of the above table is not to summarize PTE, but rather to demonstrate how PSD applicability was determined, which has not changed.

As illustrated in the above table, the proposed J.K. Smith project is subject to PSD requirements for particulate matter, sulfur dioxide, nitrogen oxides, carbon monoxide, volatile organic compounds, and sulfuric acid mist. PSD requirements apply to both the CT and CFB projects, for all the pollutants subject to PSD, regardless if the amount emitted is below the threshold for the CT portion of the project.

A PSD review involves the following six requirements:

1. Demonstration of the application of Best Available Control Technology (BACT).
2. Demonstration of compliance with each applicable emission limitation under Title 401 KAR Chapters 50 to 65 and each applicable emissions standard and standard of performance under 40 CFR 60, 61, and 63.
3. Air quality impact analysis.
4. Class I area impact analysis.
5. Projected growth analysis.
6. Analysis of the effects on soils, vegetation and visibility.

### **PM<sub>10</sub> Surrogate Policy**

On February 25, 2010, EKPC provided information demonstrating that the use of the PM<sub>10</sub> Surrogate Policy to satisfy the requirements of 401 KAR 51:017 for PM<sub>2.5</sub>, is appropriate for this project.<sup>1</sup> EKPC concluded that continued use of the PM<sub>10</sub> Surrogate Policy is necessary because there are technical difficulties which prevent EKPC from quantifying PM<sub>2.5</sub> emissions, conducting a PM<sub>2.5</sub> air quality modeling analysis and from evaluating increment consumption. To support the use of the Policy EKPC demonstrated that a direct relationship between PM<sub>10</sub> and PM<sub>2.5</sub> emissions exists for this project and that the BACT analyses performed would also represent BACT if specific PM<sub>2.5</sub> BACT analyses had been performed.

<sup>1</sup> EKPC response to comments, Exhibit 1

Technical Difficulties Demonstrating Compliance with 401 KAR 51:017

Finalized reference test methods for filterable or condensable PM<sub>2.5</sub> emissions have not been established in regulation. The lack of test methods prevents reliable emission estimates from being quantified. Also, it would be problematic to establish a PM<sub>2.5</sub> condensable or filterable BACT emission limit, as EKPC would not have a means to demonstrate compliance. Furthermore, the lack of test methods has prevented a PM<sub>2.5</sub> emissions inventory from being developed.

In addition to the lack of a PM<sub>2.5</sub> emissions inventory, a PM<sub>2.5</sub> NAAQS modeling analysis is infeasible because a regulatory model for PM<sub>2.5</sub> emissions has not been established in 40 CFR 51 Appendix W. An analysis of maximum allowable increases over baseline emissions is not possible because the maximum allowable increase for PM<sub>2.5</sub> has not been established. Also, baseline emissions cannot be established without a baseline date.

PM<sub>10</sub> is a Reasonable Surrogate for PM<sub>2.5</sub>

Without a test method for PM<sub>2.5</sub>, there is a lack of reliable data to demonstrate a direct empirical relationship between PM<sub>10</sub> and PM<sub>2.5</sub> emissions. EKPC contacted Alstom, the manufacturer of the proposed CFB boilers and controls, regarding the availability of PM<sub>2.5</sub> data. Alstom stated it “does not have any PM<sub>2.5</sub> emissions data that would be transferable to the EKPC CFB boilers”.<sup>2</sup> While AP-42 provides particle size distributions for different types of coal, there is no information for emissions from CFB boilers. With respect to filterable emissions, in general information in AP-42 shows PM<sub>2.5</sub> emissions are less than PM<sub>10</sub> emissions. Therefore, without a reliable method for estimating filterable PM<sub>2.5</sub> emissions, EKPC conservatively assumed PM<sub>2.5</sub> emissions to be equivalent to PM<sub>10</sub> emissions for the CFB boilers. Table 4-2 shows the relationship between PM<sub>10</sub> and PM<sub>2.5</sub> emissions from this project provided by EKPC.

For condensable PM<sub>2.5</sub> emissions, test data is not necessary to illustrate a statistical relationship between PM<sub>10</sub> and PM<sub>2.5</sub> because, in general, condensable PM is considered to have an aerodynamic diameter less than 2.5 µm.<sup>3</sup> Therefore, condensable PM<sub>10</sub> emissions are considered equivalent to condensable PM<sub>2.5</sub> emissions.

Table 4-2 Relationship Between PM<sub>10</sub> and PM<sub>2.5</sub> Emissions for CFBs Project

Emission Point	PM10 Emissions (TPY)	PM2.5 Emissions (TPY)	Difference (TPY)
CFB 1	157.68	157.68	0
CFB 2	160.89	160.89	0
Unit 1 Bed Ash Silo	0.75	0.75	0
Unit 1 Fly Ash Silo	0.84	0.84	0
Unit 2 Bed Ash Silo	0.75	0.75	0

<sup>2</sup> Letter Re: EKPC’s Inquiry regarding PM<sub>2.5</sub> Emissions, from Jeffrey Millikan, P.E., Senior Project Manager for ALSTOM, to Jerry Purvis, Manager of Environmental Permitting for East Kentucky Power Cooperative (Oct. 20, 2009).

<sup>3</sup> AP-42 (<1 micron)



Emission Point	PM10 Emissions (TPY)	PM2.5 Emissions (TPY)	Difference (TPY)
Unit 2 Fly Ash Silo	0.84	0.84	0
Limestone/Coal Silos 1	2.25	2.25	0
Limestone/Coal Silos 2	2.25	2.25	0
Coal Crusher House	1.88	1.88	0
Coal Piles	0.47	0.26	-0.21
Coal Piles (erosion)	0.12	0.04	-0.08
Unit 1 Cooling Tower	3.2	3.2	0
Unit 2 Cooling Tower	3.2	3.2	0
Dry FGD Lime Silo 1	1.31	1.31	0
Dry FGD Recycle Silo 1	0.38	0.38	0
Dry FGD Slaker 1	0.047	0.047	0
Dry FGD Lime Silo 2	1.31	1.31	0
Dry FGD Recycle Silo 2	0.38	0.38	0
Dry FGD Slaker 2	0.047	0.047	0
Limestone Unloading	0.0056	0.0056	0
Limestone Pile (erosion)	0.0073	0.0073	0
East Reclaim Egress	0.60	0.17	-0.43
West Reclaim Egress	0.60	0.17	-0.43
Railcar Dumper	1.18	0.13	-1.05
Paved Roadways	23.97	3.55	-20.42

Considering the information above, the Division determines that EKPC has adequately justified the use of the PM<sub>10</sub> Surrogate Policy for this project. Each PM BACT analysis performed and detailed in this section demonstrates that the control technology chosen is at least as effective as the technology that would have been chosen had a specific PM<sub>2.5</sub> BACT analysis been.

#### 4.2 Title V Operating Permit

As J.K. Smith will emit greater than 100 tons per year of several pollutants it is subject to the Title V permitting and operating requirements of 401 KAR 52:020. Kentucky's program is a combined permitting program so both PSD and Title V operating requirements are included in the initial permit.

#### 4.3 Hazardous Air Pollutants

On March 29, 2005, the U.S. EPA issued a final rule that removed coal-and oil-fired Electric Generation Units (EGUs) from the list of sources regulated under Section 112 of the Clean Air Act. On May 18, 2005, the U.S. EPA issued mercury standards and established a cap and trade program for mercury ("Clean Air Mercury Rule" or "CAMR"). Both of these decisions were vacated on February 8, 2008 by the United States Court of Appeals for the District of Columbia Circuit. As a result, new electric

generating units that are major sources of hazardous air pollutants may be subject to Section 112(g)(2) ("case-by-case MACT").

EKPC has requested imposition of an emission limit for HCl to preclude applicability of the case-by-case MACT provisions under Section 112(g). Specifically, EKPC has proposed to limit its emissions of HAPs to under 10 tons/year of a single HAP and 25 tons/year for any combination of HAPs. EKPC requests imposition of an emission limit for HCl since HCl represents more than half of the total HAP emissions from the CFB boilers and therefore, demonstration of compliance with the limits for HCl will ensure that the major source HAP thresholds for HAPs are not exceeded.

In its June 8, 2008 addenda to the application, EKPC provided the results of testing for EKPC's Gilbert CFB unit (Unit 3) at the Spurlock Station, as follows:

Table 4-2 HCl Test Results

Year	Test Results lbs of HCl/MMBtu
2005	$5.6 \times 10^{-5}$
2006	$7.1 \times 10^{-4}$
2007	$1.6 \times 10^{-4}$
Average	$3.09 \times 10^{-4}$

The HCl emission factor of  $2.93 \times 10^{-4}$  lbs/MMBtu was derived from the above test results with additional removal factored in to account for the dry scrubber with lime injection for the Smith CFBs, whereas the Gilbert dry scrubber uses ash re-injection.

EKPC proposes an initial source test to determine HCl emissions and to establish the correlation between the chlorine content of the fuel and HCl emissions. Stack tests for HCl would be performed annually to validate the correlation as necessary. The chlorine content of the fuel would be determined by collecting and analyzing weekly composite "as-fired" fuel. Monthly HCl emissions would be calculated using the following formula:

$$HCl \text{ Emissions(tons)} = P \times Fuel_{Cl} \times EF_{Cl} \times \left( \frac{36.5 \text{ lb HCl}}{35.5 \text{ lb Cl}} \right)$$

HCl Emissions = monthly HCl emissions in tons

P = monthly total fuel usage rate in tons

Fuel<sub>Cl</sub> = monthly average fuel Cl concentration, lb Cl/lb fuel, determined as follows:

$$Fuel_{Cl} = \frac{\sum_n P_n \times Cl_n}{P}$$

P<sub>n</sub> = monthly usage rate for fuel n in tons

Cl<sub>n</sub> = Cl content of fuel n

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$EF_{Cl}$ =pounds Cl emitted/pound Cl in fuel from stack testing results.

In its February 12, 2009 response to the Division's request for more information, EKPC expanded on its proposed compliance demonstration, emission factors, and the impact of startup and shutdown on compliance with the annual emission limitations proposed.

With respect to compliance demonstration and monitoring, EKPC proposed the following:

Emission Requirements:	HCl emissions from CFB1 and CFB2 shall not exceed 9 tons per year.
Monitoring Methods:	1. Initial source test. 2. Chlorine content of the fuel. 3. PM and SO <sub>2</sub> CEMS. 4. CFB boiler and FDA limestone/fresh lime injection rate.
Indicator Range:	Initial source test to establish a correlation between HCl emissions and the chlorine content and operation of the boiler and control equipment.
Data Collection Frequency:	1. Chlorine content of the fuel weekly. 2. Continuous PM and SO <sub>2</sub> CEMS and FDA limestone/fresh lime injection rate.
Averaging Period:	12-month rolling average.
Recordkeeping:	Records of the chlorine content of the fuel, the PM and SO <sub>2</sub> CEMS and FDA limestone/fresh lime injection rate data will be maintained in a designated database on-site.
Operational QA/QC:	Boiler and FDA limestone/fresh lime injection will be maintained and operated in accordance with manufacturer specifications and recommendations.

EKPC was unable to identify the source of the emission factors used in the application for metals, and so provided a revision. Its revision was based upon the U.S. EPA's 1998 "Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units -- Final Report to Congress (Report to Congress) Appendix D, which contains a listing of trace elements in coal for each coal-producing state. EKPC selected Kentucky, West Virginia, Ohio, Indiana, Illinois and Virginia as representative of coal that will be used at Smith, and then selected the highest concentration for each trace element.

Appendix C of the Report to Congress contains emission modification factors (EMFs) for various types of coal-fired unit configurations. The EMFs are fractions of the amount of a HAP compound exiting a device (boiler or air pollution control device) divided by the amount of the same HAP compound entering that device<sup>4</sup>. EKPC

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<sup>4</sup> Report to Congress, Page 3-10.

selected the tables for circulating fluidized bed furnaces (Table C-1) and flash dryer absorber/fabric filter units (Table C-20).

### **Discussion**

The table of emission factors listed on page 10 of the February 12, 2009 response illustrates that assumed control efficiencies ranged from 30 percent to over 99.9 percent, for a weighted average of 99.5 percent. While total metal HAPs are 1.03 tons per year, the uncontrolled amount is 224.78 tons per year based upon the U.S. EPA data, which is shown in the table below. This illustrates that a high level of control is required to ensure that emissions are below the requested limits.

**Table 4-3 Control Efficiencies of Metal HAPs**

<b>Pollutant</b>	<b>Highest (ppm)</b>	<b>Table C-1</b>	<b>Table C-20</b>	<b>EF (ppm)</b>	<b>Uncontrolled (tons/year)</b>	<b>Control Efficiency (percent)</b>	<b>Controlled (tons/year)</b>
Antimony	1.4	1	0.003	4.20E-03	2.30	99.70	0.01
Arsenic	23.2	0.77	0.002	3.57E-02	38.11	99.85	0.06
Beryllium	3.17	0.56	0.001	1.78E-03	5.21	99.94	0.00
Cadmium	0.98	1	0.04	3.92E-02	1.61	96.00	0.06
Chromium	16.3	0.46	0.02	1.50E-01	26.77	99.08	0.25
Cobalt	7.2	1	0.001	7.20E-03	11.83	99.90	0.01
Lead	24.51	0.42	0.003	3.09E-02	40.26	99.87	0.05
Manganese	38	0.63	0.002	4.79E-02	62.42	99.87	0.08
Mercury	0.22	1	0.7	1.54E-01	0.36	30.00	0.25
Nickel	17.9	0.67	0.01	1.20E-01	29.40	99.33	0.20
Selenium	3.97	0.84	0.01	3.33E-02	6.52	99.16	0.05
Total					224.78	99.54	1.03

The same applies to HCl and HF for which EKPC assumes a control efficiency of 99.8 percent. Uncontrolled emissions for HCl would be over 1900 tons/year and for HF would be over 300 tons per year. Therefore, in lieu of the SO<sub>2</sub> and PM CEMS, HCl CEMS shall be used as in indicator of compliance, as follows:

- (1) If the monthly average HCl emissions based on CEMS data equal or exceed 0.75 tons, the permittee shall notify the Division, investigate the cause and implement corrective measures. If the monthly average HCl emissions based on the CEMS data for the next month equal or exceed 0.75 tons, the permittee shall take corrective action, provide notification to the Division, and schedule a Method 26 or an approved alternative test within 30 days to demonstrate compliance with the annual limit.
- (2) For HCl monitored emission results less than the minimum detection level of the CEMS, the permittee shall report the missing data as 75% of the minimum detection level. For periods of missing data due to periods of maintenance or instrument downtime, the missing data shall be assumed to be the highest recorded concentration from the 30 day period preceding or the highest concentration from the 30 day period following the period of missing data.

- (3) The permittee shall take a sample of "as received" fuel per delivery by supplier. The samples taken shall be analyzed and numerically averaged based on a weighted average of tons of coal received by each supplier to determine chlorine content on a quarterly basis. This data, along with the baseline data established during the initial compliance and subsequent tests shall be used to demonstrate compliance with the emission limits for HCl.
- (4) The permittee shall report semiannually the HCl and total HAP emissions, and the calculations and correlations used to determine the HCl and total HAP emissions.

For the remaining HAPs, EKPC is proposing that emission factors will be used to demonstrate compliance. A comparison of the emission factors contained in EKPC's application with AP-42 reveals differences that often exceed several orders of magnitude. EKPC's application contains numerous HAPs that are not included in AP-42, while AP-42 contains six pollutants not contained in the application: 5-methyl chrysene, cyanide, dimethyl sulfate, ethylene dibromide, methyl hydrazine, and chromium VI. The AP-42 emission factor for cyanide is the second highest HAP, below HCl. However, the emission factor has a "D" rating, which the U.S. EPA describes as:

*"D--Below average: The emission factor was developed only from A- and B rated test data from a small number of facilities, and there is reason to suspect that these facilities do not represent a random sample of the industry. There also may be evidence of variability within the source category population. Limitations on the use of the emission factor are noted in the emissions factor table."*

Appendix A contains a comparison of HAPS emission factors from the application and AP-42. If the highest emission factor is used to estimate potential emissions, the result is 13.4 tons/year for CFB1 and 13.7 tons/year for CFB2, each of which is well under the requested 25 ton limit for all HAPs. However, this estimate is based upon non-unit specific emission factors and it is unknown if these emission factors accurately represent the emissions from the proposed CFBs. Therefore, EKPC should test the HAPs that comprise the majority of HAP emissions to determine site specific emission factors.

Appendix B contains a list of HAPs, sorted from highest to lowest emissions. The pollutants that emit greater than 0.2 tons per year collectively account for 10.80 tons, which is over 80 percent of potential HAP emissions. Testing those pollutants to obtain more accurate emission factors would provide adequate assurance that total HAP emissions will be under 25 tons/year from each unit. These pollutants are: acetaldehyde, acrolein, arsenic, benzene, benzyl chloride, chromium, chromium VI, cyanide, hydrogen chloride, hydrogen fluoride, isophorone, lead, manganese, mercury, methyl chloride, nickel, and selenium<sup>5</sup>.

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<sup>5</sup> Methyl ethyl ketone was removed from the list of HAPs in Section 112 of CAA on December 19, 2005.

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To provide additional assurance that HAPs emissions remain below Section 112(g) applicability thresholds, emissions limits for each CFB shall be set at 9 tons for a single HAP and 22.5 tons for all HAPs combined for any 12-consecutive months.

#### **4.4 40 CFR Part 60, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units**

40 CFR Part 60, Subpart Da (Subpart Da) requires all new, modified, or reconstructed steam generating units with a maximum heat input capacity greater than 250 MMBtu/hour for which construction is commenced after September 18, 1978 to meet limitations on emissions of PM, SO<sub>2</sub>, NO<sub>x</sub>, and mercury. Subpart Da applies to the CFBs at J.K. Smith, although any emission limits derived from the BACT analysis that are more stringent than Subpart Da emission limits would apply instead.

##### **4.4.1 Particulate Matter and Opacity**

Pursuant to 40 CFR 60.42Da(a), the PM emissions limit for new electric steam generating units are:

- (1) 18 ng/J(0.14 lb/MWh) gross energy output; or 6.4 ng/J(0.015 lb/MMBtu heat input, or
- (2) 13 ng/J(0.03 lb/MMBtu) heat input and 0.1 percent of the combustion concentration determined according to the procedure in 40 CFR 60.48Da(o)(5) (99.9 percent reduction).

EKPC proposes a BACT emission limit of 0.012 lb/MMBtu (total) and 0.009 lb/MMBtu (filterable only), which is more stringent than required by Subpart Da.

Pursuant to 40 CFR 60.42Da(b) opacity is limited to 20 percent (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements in Subpart Da are exempt from the opacity standard. EKPC has elected to use a PM CEMS, and therefore is exempt from opacity standards.

##### **4.4.2 Sulfur Dioxide**

The SO<sub>2</sub> emission limit for new electric utility steam generating units is 180 ng/J(1.4 lb/MWh) gross energy output or 95 percent reduction regardless of type of fuel, with one exception. Units that burn over 75 percent coal refuse (by heat input) is 180 ng/J (1.4 lb/MWh) gross energy output or 94 percent reduction. The BACT emission limit is 0.075 lbs/MMBtu, achieved via limestone injection and FDA using fresh lime infection for a total of 99 percent reduction, which is more stringent than required by Subpart Da. SO<sub>2</sub> emissions will be monitored by SO<sub>2</sub> CEMS.

#### **4.4.3 Nitrogen Oxides**

The NO<sub>x</sub> emission limit for new electric utility steam generating units is 130 ng/J (1.0 lb NO<sub>x</sub>/MWh) gross energy output (equivalent to 0.11 lb/MMBtu heat input) regardless of the type of fuel. Compliance with this emission limit is determined on a 30-day rolling average basis using testing, monitoring, and other compliance provisions in the rule for the output-based NO<sub>x</sub> standards. The BACT NO<sub>x</sub> emission limit is 0.07 lbs/MMBtu, which is more stringent than required by Subpart Da. NO<sub>x</sub> emissions will be monitored by NO<sub>x</sub> CEMS.

#### **4.4.4 Mercury**

On March 15, 2005, the U.S. EPA issued the Clean Air Mercury Rule (CAMR). On February 8, 2008, the D.C. Circuit vacated U.S. EPA's rule removing power plants from the Clean Air Act list of sources of hazardous air pollutants. At the same time, the Court vacated the Clean Air Mercury Rule, a part of which established regulation of mercury under Section 111 of the CAA. Therefore, the mercury requirements in 40 CFR Part 60, Subpart Da have been vacated.

U.S. EPA has decided to develop emissions standards for power plants under the Section 112 of the CAA, consistent with the D.C. Circuit's opinion on the CAMR<sup>6</sup>. These regulations have not yet been promulgated. As no state or federal standard is applicable to these emissions at this time, mercury is regulated under 401 KAR 63:020. Until such time as the U.S. EPA promulgates new rules for mercury, mercury requirements will be patterned after the requirements in 40 CFR Part 60, Subpart Da. Since future publications of Subpart Da will not contain references to the requirements associated with CAMR, all references in the permit to mercury requirements associated with Subpart Da are based on the March 15, 2005 Federal Register publication.

Mercury emissions shall not exceed  $[(20 \times 10^{-6} \text{ lb/MWh} \times \text{MWh of bituminous coal}) + (16 \times 10^{-6} \text{ lb/MWh} \times \text{MWh coal refuse})] / [\text{MWh of bituminous coal} + \text{MWh coal refuse}]$  on an output basis averaged on a 12-month rolling average basis [401 KAR 63:020].

Mercury shall be monitored either by mercury (Hg) CEMS or sorbent trap monitoring system (as defined in 40 CFR 72.2). If Hg CEMS is chosen, the CEMS must be installed, operated, and maintained according to Performance Specification 12A in Appendix B to 40 CFR Part 60. If a sorbent trap monitoring system is selected to monitor Hg concentration, the procedures described in 40 CFR 75.15 and Appendix K to 40 CFR Part 75 shall be followed.

#### **4.5 Phase II Acid Rain Permits**

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<sup>6</sup> See <http://www.epa.gov/camr/>.

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Title IV of the Clean Air Act requires reductions in emissions of SO<sub>2</sub> and NO<sub>x</sub> in an effort to reduce formation of acid rain. U.S. EPA, in promulgating regulations in 40 CFR Part 72, requires the submittal of application forms (incorporated by reference in 401 KAR 52:060) no later than two years prior to commencing operations of a regulated unit. This source is required to apply for a Phase II Acid Rain permit. Under Phase II Acid Rain requirements, filing of a Title V application for a new source subject to the Acid Rain requirements requires the source to file the Phase II application at the same time. Additionally, Acid Rain regulations, 40 CFR 72 through 40 CFR 78 apply. Part 75 requires continuous emission monitoring for NO<sub>x</sub> and SO<sub>2</sub>.

#### **4.6 NO<sub>x</sub> Budget Trading Program, CAIR NO<sub>x</sub> and SO<sub>2</sub> Trading Programs**

On May 12, 2005, U.S. EPA published the Clean Air Interstate Rule (CAIR). The CAIR requires states to reduce emissions of nitrogen oxides and sulfur dioxide that contribute significantly to nonattainment and maintenance problems in downwind states with respect to the national ambient air quality standards for fine particulate matter (PM<sub>2.5</sub>) and 8-hour ozone. On April 28, 2006, U.S. EPA published Federal Implementation Plans (FIP) which are similar in structure to the existing Acid Rain and NO<sub>x</sub> Budget cap-and-trade rules, with the addition of NO<sub>x</sub> seasonal requirements. The U.S. EPA will withdraw the FIP for any state once that state's own State Implementation Plan (SIP) is approved. Kentucky's regulations are codified in 401 KAR 51:210, CAIR NO<sub>x</sub> annual trading program, 401 KAR 51:220, CAIR NO<sub>x</sub> ozone season trading program, and 401 51:230, CAIR SO<sub>2</sub> trading program.

On July 11, 2008, the United States Circuit Court of Appeals for the District of Columbia issued an opinion vacating and remanding CAIR to the U.S. EPA. However, parties to the litigation requested rehearing of aspects of the Court's decision, including the vacatur of the rules. On December 23, 2008, the Court granted rehearing only to the extent that it remanded the rules to EPA without vacating them<sup>7</sup>. Therefore, CAIR is listed as an applicable regulation.

The first phase of NO<sub>x</sub> reductions starts in 2009 (covering 2009-2014) and the first phase of SO<sub>2</sub> reductions starts in 2010 (covering 2010-2014). The second phase of both SO<sub>2</sub> and NO<sub>x</sub> reductions starts in 2015 (covering 2015 and thereafter.) CAIR designated representatives are required to submit applications 18 months before the later of January 1, 2009 for NO<sub>x</sub> (January 1, 2010 for SO<sub>2</sub>) or the date on which the CAIR unit commences commercial operation. EKPC filed a CAIR application on February 26, 2008.

#### **4.7 40 CFR Part 64, Compliance Assurance Monitoring**

Compliance Assurance Monitoring (CAM) is applicable to certain units that rely upon control devices to comply with emission limits. Generally, units that have potential uncontrolled emissions that are greater than or equal to that required for a source to be

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<sup>7</sup> See <http://www.epa.gov/air/interstateairquality/> for the latest information.



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classified as a major source and uses a control device to comply with an emission limit are subject to CAM, with some exceptions.

Emission Units 11 and 12 - CFB Boilers - CAM applies to H<sub>2</sub>SO<sub>4</sub>, and HCl. PM, SO<sub>2</sub>, and NO<sub>x</sub> are subject to 40 CFR 60, Subpart Da and therefore are exempted from CAM [40 CFR 64.2(b)(1)(i)]. There are no control devices for CO and VOCs so CAM does not apply [40 CFR 64.2(a)(2)]. None of the remaining pollutant potential pre-control device emissions exceed major source thresholds and therefore CAM does not apply [40 CFR 64.2(a)(3)]. EKPC proposes to use SO<sub>2</sub> CEMS as an indicator of H<sub>2</sub>SO<sub>4</sub> emissions and HCl CEMS as an indicator of HCl emissions.

Emission Unit 13 - Ash Handling System - CAM applies to PM. EKPC proposes to use opacity as an indicator of PM emissions.

Emission Unit 14 - Coal Crushing and Silo Storage - PM is subject to 40 CFR 60, Subpart Y and therefore is exempted from CAM [40 CFR 64.2(b)(1)(i)].

Emission Unit 15 - Coal Stockpile Storage and Handling - CAM does not apply because uncontrolled PM emissions are less than major source [40 CFR 64.2(a)(3)].

Emission Unit 16 - Lime/Limestone Silo Storage and Handling - CAM does not apply to limestone material handling units. These units are subject to 40 CFR 60 Subpart OOO and therefore are exempted from CAM [40 CFR 64.2(b)(1)(i)]. CAM does apply to PM emissions from the lime material handling units, since these units are not subject to 40 CFR 60 Subpart OOO. As lime and limestone processes are similar, the monitoring requirements in 40 CFR Subpart OOO have been adopted as CAM for lime material handling to the extent compatible with the lime material handling's governing regulation, 401 KAR 59:010, New process operations.

Emission Unit 17 - Limestone Unloading and Storage - CAM does not apply because uncontrolled PM emissions are less than major source [40 CFR 64.2(a)(3)].

Emission Unit 18 - Cooling Towers - CAM does not apply because uncontrolled PM emissions are less than major source [40 CFR 64.2(a)(3)].

Emission Unit 19 - Haul Roads - CAM does not apply because uncontrolled emissions are less than major source [40 CFR 64.2(a)(3)].

#### **4.8 40 CFR Part 60, Subpart Y, Standards of Performance for Coal Preparation Plants**

This regulation requires certain coal processing facilities to comply with particulate matter standards. Activities regulated by this NSPS include crushing, screening, conveying and transferring of coal. A proposed rule change was published in the Federal Register on May 28, 2008, then later revised on May 27, 2009. The final rule was published on October 08, 2009.

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**4.9 40 CFR Part 60, Subpart OOO, Standards of Performance Nonmetallic Mineral Processing Plants**

This regulation applies to the limestone handling associated with the proposed project. Affected facilities are crushers, grinding mills, screening operations, bucket elevators, belt conveyors, bagging operations, storage bins and enclosed truck or railcar loading stations. A proposed rule change was published in the Federal Register on April 22, 2008, and a final rule was published on April 28, 2009.

**4.10 401 KAR 50:042, Good Engineering Practice Stack Height**

This regulation requires that good engineering practice (GEP) stack height shall be determined by the following equation:

$$H_g = H + 1.5L$$

where:

$H_g$  = GEP stack height measured from the ground-level elevation at the base of the stack

$H$  = Height of nearby structure(s) measured from the ground-level elevation at the base of the stack

$L$  = lesser dimension (height or projected width) of nearby structure(s); or

the height demonstrated by an approved fluid model or field study which ensures that the emissions from a stack do not result in excessive concentrations of any air pollutant as a result of atmospheric downwash, wakes, or eddy effects created by the source itself, nearby structures, or nearby terrain features.

**4.11 401 KAR 50:045, Performance Tests**

This regulation specifies the procedures that should be followed when testing is required.

**4.12 401 KAR 50:055, General Compliance Requirements**

This regulation establishes requirements for compliance during shutdown and malfunctions, establishes requirements for demonstrating compliance with standards, and other general requirements.

**4.13 401 KAR 51:160, NO<sub>x</sub> Trading Program**

Pursuant to the federal NO<sub>x</sub> State Implementation Plan (SIP) Call, this administrative regulation provides for the regional control of nitrogen oxides (NO<sub>x</sub>) emissions by establishing requirements for large stationary internal combustion engines. A CAIR permit application, which replaces the NO<sub>x</sub> Budget application, was included with the

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PSD application. Requirements contained in that application were incorporated into and made part of the NO<sub>x</sub> Budget Permit. Pursuant to 401 KAR 52:020, Section 3, the source shall operate in compliance with those requirements.

#### **4.14 401 KAR 51:210, CAIR NO<sub>x</sub> Annual Trading Program**

401 KAR 51:210 requires affected units to acquire NO<sub>x</sub> emission allowances equal to their annual NO<sub>x</sub> emissions. EKPC will acquire allowances necessary to meet compliance requirements of all applicable state and federal NO<sub>x</sub> trading programs.

As previously noted, on July 11, 2008, the United States Circuit Court of Appeals for the District of Columbia issued an opinion vacating and remanding CAIR to the U.S. EPA. However, parties to the litigation requested rehearing of aspects of the Court's decision, including the vacatur of the rules. On December 23, 2008, the Court granted rehearing only to the extent that it remanded the rules to EPA without vacating them<sup>8</sup>. Therefore, CAIR is listed as an applicable regulation.

The CAIR permit application was received with the PSD application (Appendix B). Requirements contained in that application were incorporated into and made part of the CAIR permit.

#### **4.15 401 KAR 51:220, CAIR NO<sub>x</sub> Ozone Season Trading Program**

401 KAR 51:220 requires the control of nitrogen oxides (NO<sub>x</sub>) emissions from large boilers and turbines used in power plants pursuant to the federal mandate published under the Clean Air Interstate Rule (CAIR), 40 C.F.R. 96.301 to 96.388. The CFBs are defined as CAIR NO<sub>x</sub> Ozone Season units since they are subject to 40 CFR 96.304.

#### **4.16 401 KAR 51:230, CAIR SO<sub>2</sub> Trading Program**

This regulation establishes the provisions of the CAIR SO<sub>2</sub> Trading Program as codified in 40 CFR 96.201 to 96.288.

#### **4.17 401 KAR 52:060, Acid Rain Permits**

This regulation incorporates by reference 40 CFR Parts 72 to 78. Since the CFBs will be constructed after the allowance allocations, they will receive no SO<sub>2</sub> allowances. The NO<sub>x</sub> limit and the averaging plans are established by 40 CFR 75 and 76. The application contained an Acid Rain Permit Application. Requirements contained in that application were incorporated into and made part of the Acid Rain permit.

#### **4.18 401 KAR 59:010, New Process Operations**

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<sup>8</sup> See <http://www.epa.gov/air/interstateairquality/> for the latest information.

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This regulation applies to each affected facility or source, associated with a process operation, which is not subject to another emission standard with respect to particulate matter.

#### **4.19 401 KAR 63:010, Fugitive Emissions**

Requirements apply to fugitive dust emissions from roads, material handling and storage operations. This regulation requires the owner or operator to utilize reasonable precautions to prevent particulate matter from becoming airborne and prohibits visible fugitive dust at the property line.

#### **4.20 401 KAR 63:020, Potentially Hazardous Matter or Toxic Substances (State Only Requirement)**

This regulation applies to certain facilities that emit potentially hazardous matter or toxic substances that are not elsewhere subject to regulation.

The Division has reviewed the AERMOD air dispersion model screening of potentially hazardous substances that may be emitted by the facility based upon the process rates, material formulations, stack heights and other pertinent information provided by the applicant. A summary of the potentially hazardous substances which were screened can be found in the Revised Class II Modeling submittal dated May 22, 2009. In addition, a separate submittal revising the air toxics analysis was submitted on December 9<sup>th</sup>, 2009. The modeled worst case impacts were compared to the level of concern (LOC) that triggers additional review and/or more detailed modeling. The LOC is derived as the one in a million cancer risk value or an exceedance of the Reference Concentration (RfC) based on an annual average. The carcinogenic risk is calculated according to the formula:

$$\text{Risk} = \text{Inhalation Unit Risk (ug/m}^3\text{)}^{-1} \times \text{Concentration (ug/m}^3\text{)}$$

The inhalation unit risk values and RfC's are primarily obtained from EPA's Regional Screening Level (RSL) table<sup>9</sup>.

The maximum modeled concentrations did not exceed the LOC for the compounds modeled except for chromium. The maximum annual chromium concentration modeled by the facility is  $1.10 \times 10^{-3}$  ug/m<sup>3</sup> which exceeds the LOC for total chromium which is  $8.3 \times 10^{-5}$  ug/m<sup>3</sup>. As previously noted in Section 4.3, the estimate is based upon non-unit specific emission factors and it is unknown if these emission factors accurate predictors of the emissions from the proposed CFBS. As a result, the Division is requiring stack testing for several HAPs, including chromium and chromium VI. Within 60 days of receipt of the testing results, EKPC should submit an evaluation of chromium, chromium VI and any HAP emissions that are required to be tested and exceed the estimates in Appendix A, column labeled "Highest EF (lbs/MMBtu)". The evaluation should either

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<sup>9</sup> See [http://www.epa.gov/reg3hscd/risk/human/rb-concentration\\_table/Generic\\_Tables/](http://www.epa.gov/reg3hscd/risk/human/rb-concentration_table/Generic_Tables/).

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demonstrate compliance with 401 KAR 63:020 or provide a schedule for bringing the units into compliance.

**5. BEST AVAILABLE CONTROL TECHNOLOGY (BACT) REVIEW**

Pursuant to 401 KAR 51:001/51:001E, Section 1, "Best available control technology" or "BACT" means an emissions limitation, including a visible emission standard, based on the maximum degree of reduction for each regulated NSR pollutant that will be emitted from a proposed major stationary source or major modification that:

- (a) Is determined by the cabinet on a case-by-case basis after taking into account energy, environmental, and economic impacts and other costs, to be achievable by the source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of that pollutant;
- (b) Does not result in emissions of a pollutant that would exceed the emissions allowed by an applicable standard of 40 C.F.R. Parts 60 and 61; and
- (c) Is satisfied by a design, equipment, work practice, or operational standard or combination of standards approved by the cabinet, if:
  - 1. The cabinet determines technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible;
  - 2. The standard establishes the emissions reduction achievable by implementation of the design, equipment, work practice or operation; and
  - 3. The standard provides for compliance by means that achieve equivalent results.

The following pollutants exceed significant levels and are subject to BACT: particulate matter (PM), particulate matter less than 10 microns (PM<sub>10</sub>/PM<sub>2.5</sub>), sulfur dioxide (SO<sub>2</sub>), nitrogen oxides (NO<sub>x</sub>), carbon monoxide (CO), volatile organic compounds (VOC), and sulfuric acid mist (H<sub>2</sub>SO<sub>4</sub>).

EKPC submitted a top-down Best Available Control Technology (BACT) analysis that applies procedures consistent with the U.S. EPA guidance document, "New Source Review Workshop Manual" (U.S. EPA, October 1990) and consistent with the definition of BACT in 401 KAR 51:001/51:001E, Section 1 above. The key steps involved with the top-down BACT process are as follows:

- 1. Identify all control technologies;
- 2. Eliminate technically infeasible options;

3. Rank remaining control technologies by control effectiveness;
4. Evaluate most effective controls considering economic, environmental, and energy impacts, and document results; and
5. Select BACT.

### **5.1 Circulating Fluidized Bed (CFB) Boilers**

EKPC is proposing to construct two CFB boilers with a nominal power output of 278 MW each to serve as baseload generation units. BACT applies to nitrogen oxides, sulfur dioxide, particulate matter, carbon monoxide, volatile organic compounds, and sulfuric acid mist.

EKPC is designing the proposed CFB boilers to fire run of mine bituminous coal and coal waste, with the design fuel consisting of a blend of bituminous coal and locally available coal waste. Design characteristics are:

- 8000 Btu/lb heat content
- 40 percent ash content
- 3 percent sulfur content
- 10 percent moisture

EKPC has selected limestone injection, a Flash Dryer Absorber (FDA) using fresh lime injection, Selective Noncatalytic Reduction (SNCR), and fabric filter as controls.

#### **5.1.1 CFB - Nitrogen Oxides (NO<sub>x</sub>) Controls**

EKPC identified the following NO<sub>x</sub> controls:

- Combustion Controls
- Non-Thermal Plasma Reactor
- Carbon Injection
- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)

EKPC rejected Combustion Controls, Non-Thermal Plasma Reactor, Carbon Injection, and Selective Catalytic Reduction due to either technical infeasibility, lack of availability, or cost-effectiveness as discussed below.

##### **Combustion Controls**

EKPC categorized NO<sub>x</sub> controls into two types of technologies: combustion controls and post-combustion controls. Combustion controls inhibit the formation of NO<sub>x</sub>, whereas post combustion controls remove a portion that was formed during combustion. Combustion controls include staged combustion,

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low-NO<sub>x</sub> burners/overfire air, flue gas recirculation (FGR), fuel reburning, low excess air, reduced air preheat, and reducing residence time.

Combustion control is inherent in CFB boilers. As noted in "Multipollutant Emission Control Technology Options for Coal-fired Power Plants" (EPA-600/R-05/034, March 2005<sup>10</sup>):

*"The difference of CFB relative to PC boiler stems from the lower operating temperature and the injection of limestone in the furnace to capture SO<sub>2</sub> emissions. Typical maximum furnace temperature in a CFB boiler are in the 1500-1600 °F (820-870 °C) range, while conventional PC boilers operate at 2200-2700 °F (1200-1500 °C). This low combustion temperature limits the formation of NO<sub>x</sub> and is the optimum temperature range for in-situ capture of SO<sub>2</sub>."*

EKPC noted that the NO<sub>x</sub> emission level for CFB boilers without add-on controls has been reported as 0.15 lb/MMBtu.

#### Non-Thermal Plasma Reactor

According to a U.S. EPA Technical Bulletin, "Nitrogen Oxides (NO<sub>x</sub>), Why and How They Are Controlled", EPA 456/F-99-006R, November 1999<sup>11</sup>, non-thermal plasma reactor is a control technique that uses methane and hexane as reducing agents to remove NO<sub>x</sub>. The reducing agents are ionized by a transient high voltage and reacts with NO<sub>x</sub> to achieve a 94 percent reduction. It is not known to have been commercially demonstrated<sup>12</sup> for NO<sub>x</sub> control on CFB boilers<sup>13</sup>.

#### Carbon Injection

According to the same Technical Bulletin, carbon injection is a control technique involving the injection of carbon into the air flow to finish the capture of NO<sub>x</sub>. It is not known to have been commercially demonstrated for NO<sub>x</sub> control on CFB boilers.

#### Selective Catalytic Reduction

SCR is a post-combustion control technology that utilizes injection of ammonia in the presence of a catalyst. The reactions take place at an optimal temperature of around 700 °F, with a typical range between 650 and 800 °F. However, the presence of alkaline particulate matter emitted from a CFB boiler could poison

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<sup>10</sup> See [www.epa.gov/airmarkt/resource/docs/multipreport2005.pdf](http://www.epa.gov/airmarkt/resource/docs/multipreport2005.pdf)

<sup>11</sup> See [www.epa.gov/ttn/catc/dir1/fnoxdoc.pdf](http://www.epa.gov/ttn/catc/dir1/fnoxdoc.pdf)

<sup>12</sup> See for example a presentation entitled "Round 1 Solicitation Technical Issues, CCPI Round 2 Planning Workshop Pittsburgh, PA, August 26, 2003 <http://www.netl.doe.gov/publications/proceedings/03/ccpi/McMahon.Technical%20Lessons%20Learned%20TJM%203a.pdf>

<sup>13</sup> See for example, a US EPA report entitled "Using Non-Thermal Plasma to Control Air Pollutants" (<http://www.epa.gov/ttn/catc/dir1/fnonthrm.pdf>). See also [http://www.powerspan.com/ECO-SO2\\_overview.aspx](http://www.powerspan.com/ECO-SO2_overview.aspx), which clarifies that the First Energy project described in the US EPA report did not involve NO<sub>x</sub> control, nor does the American Municipal Power project in Meigs County, Ohio. Furthermore, both projects involve pulverized coal boilers and not CFB boilers.

the catalyst, and hence is technically infeasible unless the alkaline particulate matter is removed first.

SCR could be applied after particulate matter removal, however the temperature would be below that necessary for the catalyst. A catalyst that functions at lower temperatures is theoretically possible. However, EKPC indicated that to its knowledge, no low temperature catalysts for SCR control of NO<sub>x</sub> from a CFB boiler exists at this time.

EKPC indicated that heat exchange equipment and additional fuels would have to be used to reheat the gas stream after the baghouse, which may be technically feasible, but is not cost-effective due to the additional materials, fuel, and operational costs. Refer to the cost analysis in the next section.

#### Selective Non-Catalytic Reduction

SNCR is a post-combustion control technology that utilizes injection of either ammonia or urea in the gas stream, but without the presence of a catalyst. Since no catalyst is used, NO<sub>x</sub> removal is accomplished via the thermal decomposition of ammonia, which results in reduction of NO<sub>x</sub> to produce nitrogen gas and water. NO<sub>x</sub> removal efficiency is optimized in a temperature range of 1700 to 1900 °F, with typical removal efficiencies in the 50 percent range.

#### Rank Technically Feasible Control Options by Effectiveness

EKPC identified 3 options it deemed technically feasible for control of NO<sub>x</sub> emissions from a CFB boiler. These are: CFB with no add on controls, SNCR, and SCR.

Table 5-1 Technically Feasible NO<sub>x</sub> Control Technologies

Control Technology	NO <sub>x</sub> Emission Rate (lb/MMBtu)	Maximum Annual Emissions (tons per year) <sup>2</sup>	Annual Emissions Reduction Compared to Base Case (tons per year)	Percent Reduction from Base Case
CFB + SCR <sup>1</sup>	0.015	197.1	1773.9	90
CFB + SNCR	0.07	919.8	1051.2	53
CFB (Base Case)	0.15	1971.0	-	-

Note 1: EKPC indicated that it is not aware of any coal-fired boiler achieving the SCR emission rate.

Note 2: Based upon a nominal heat input rate of 3000 MMBtu/hr and 100 percent capacity.

Since there are no coal-fired CFB boilers with SCR, EKPC assumed that the level of reduction attainable would be comparable to the use of SCR on a pulverized coal boiler.

EKPC initially analyzed costs by assuming a 90 percent capacity factor. This was revised at the Division's request because EKPC was not requesting a 90 percent capacity limitation and therefore, the original analysis did not accurately reflect potential to emit.



Flue Gas Reheat - Based upon an estimate supplied by Alstom<sup>14</sup>, it would require approximately 246 MMBtu/hour heat input to raise the temperature of the flue gas from 190 °F to 500 °F. EKPC estimated the average cost of natural gas to be \$9.873/MMBtu. The annual cost of the natural gas is:

$$\$9.873/\text{MMBtu} \times 246 \text{ MMBtu/hr} \times 8760 \text{ hr} = \$21,275,920/\text{yr}$$

The natural gas reheat would also result in additional NO<sub>x</sub>, which EKPC estimated at 180 tons/year, which would result in 20 tons/year at a 90 percent control efficiency. The cost of the reheat fuel measured in terms of tons of NO<sub>x</sub> removed is:

$$\$21,275,920/\text{year} / (1773.9 - 20) \text{ tons of NO}_x \text{ removed per year} = \$12,131 \text{ per ton of NO}_x \text{ removed}$$

The incremental cost between SCR and SNCR for fuel alone is:

$$\$21,275,920/\text{year} / (1753.9 - 1051.2) \text{ tons of NO}_x \text{ removed per year} = \$30,277 \text{ per ton of NO}_x \text{ removed}$$

SCR vs. SNCR - Initially, EKPC did not provide any additional cost information related to SCR since the cost for reheating the flue gas alone was cost prohibitive. However, in response to the Division's request, EKPC provided a cost estimate for a tail-end SCR. The following table summarizes the results of EKPC's analysis, and is based on a cost estimate from Power Environmental Control Systems, North America, a division of Alstom, Inc.<sup>15</sup>, and use of the cost methodology from "EPA Air Pollution Control Cost Manual, Sixth Edition" (CCM). It includes a tail-end SCR with natural gas reheat including the SCR reactor, catalyst, gas to gas heat exchanger, reheat gas burner, ammonia feed system, and associated ductwork and structural support.

**Table 5-2 Tail-End SCR Cost Analysis**

Direct Capital Costs			
	Purchased Equipment Cost	Alstom, Inc.	\$60,000,000
	Instrumentation	Alstom, Inc.	\$0
	Sales Tax	None	\$0
	Freight	Alstom, Inc.	\$0
	Direct Installation (SCR)	Alstom, Inc.	\$0
(A) Total Direct Capital Costs			\$60,000,000
Indirect Installation Costs			
	General Facilities	CCM, 0.05xA	\$3,000,000
	Engineering and Home Office Fees	CCM, 0.1xA	\$6,000,000
	Process Contingency	CCM, 0.05xA	\$3,000,000

<sup>14</sup> See Appendix D to the application, letter dated April 2, 2008 from Jeff Millikan, ALSTOM Power ECS, Project Manager JK Smith Station to Gary Crawford, VP Engineering & Construction, EKPC.

<sup>15</sup> See letter dated July 22, 2008 from Jeffrey Millikan, P.E., Project Manager, included as Attachment 1 in EKPC's July 29, 2008 response to the Division's June 5, 2008 Notice of Deficiency.

(B) Total Indirect Installation Costs		\$12,000,000	
(C) Project Contingency	CCM, 0.15x(A+B)	\$10,800,000	
(D) Total Plant Cost	A+B+C	\$82,800,000	
(E) Allowance for FDC	CCM	\$0	
(F) Royalty Allowance	CCM	\$0	
(G) Preproduction Costs	CCM, 0.02xD	\$1,656,000	
(H) Inventory Capital	Included in A	\$0	
(I) Initial Catalyst and Chemicals	Included in A	\$0	
(TCI) Total Capital Investment	D+E+G+H+I	\$84,456,000	
Direct Annual Costs			
	Natural Gas Reheat Annual Cost	Alstom, Inc.	\$21,275,920
	Annual Reagent (Ammonia Cost)	CCM	\$528,779
	Annual Catalyst Replacement Cost	EKPC	\$1,000,000
	Annual Electrical Cost	CCM	\$472,462
	Annual Maintenance Cost	CCM, 0.015xTCI	\$1,266,840
Total Direct Annual Cost		\$24,544,001	
(IDAC) Total Indirect Annual Cost	CCM, 7 percent interest for 20 years	\$7,972,049	
(TAC) Total Annual Cost	DAC+IDAC	\$32,516,050	
NO <sub>x</sub> Removed, tons	0.15 lb/MMBtu to 0.015 lb/MMBtu +160 tons/yr	1,774	
Cost Effectiveness, \$/ton	TAC/Tons Removed	\$18,330	

EKPC's analysis resulted in a cost-effectiveness of \$16,641 per ton of NO<sub>x</sub> removed, but it assumed that 180 tons/year attributed to additional NO<sub>x</sub> from burning natural gas would be removed. As noted above, 180 tons is the uncontrolled amount and 20 tons would result after application of the SCR, so only 160 tons of NO<sub>x</sub> is removed.

As the cost to reheat the flue gas is a significant expenditure with respect to the use of SCR, the Division requested information about the feasibility of the use of low temperature catalysts or the use of heat already generated by the boiler. The previously referenced letter from Alstom indicated that "(l)ow temperature catalyst is not feasible for any coal-fired application because of ammonium bisulfate fouling of the catalyst" and that use of steam reheat from the CFB boiler could not provide the quantity of steam required without significantly reducing its ability to generate electric power and would require a very large and costly heat exchanger. Alstom estimated that that it would require approximately 60 MW and EKPC estimated that the cost of this lost power would be approximately \$28,000,000 annually, based upon an average power cost of \$0.06/kw and 90 percent capacity factor), which is higher than the annual fuel cost estimated for a tail-end SCR with natural gas reheat as opposed to steam reheat.

Therefore, the Division concurs that a tail-end SCR with low temperature catalyst is currently not feasible and that a tail-end SCR with a high temperature catalyst is not cost-effective.

### Revised Cost Analysis

In response to comments, EKPC filed a revised cost analysis. However, it does not change the Division's conclusions. The revised numbers are as follows:

Table 5-2Revised Tail-End SCR Cost Analysis

Direct Capital Costs			
	SCR	Alstom, Inc.	\$20,000,000
	Gas to Gas Heat Exchanger	Alstom, Inc.	\$5,000,000
	Burner and Ductwork	Alstom	\$5,000,000
	Freight	Alstom	Included
	Construction and Installation (SCR)	Alstom	\$25,000,000
	Foundations	Stanley Consultants	\$800,000
	Utility Systems	Stanley Consultants	\$500,000
	Electrical Work	Stanley Consultants	\$100,000
	Controls	Stanley Consultants	\$50,000
Total Direct Capital Costs (A)			\$56,450,000
Indirect Installation Costs			
	General Facilities	CCM, 0.05xA	\$2,822,500
	Engineering and Home Office Fees	CCM, 0.10xA	\$5,645,000
	Process Contingency	CCM, 0.05xA	\$2,822,000
(B) Total Indirect Installation Costs			\$11,290,000
(C) Project Contingency		CCM, 0.15x(A+B)	\$10,161,000
(D) Total Plant Cost		A+B+C	\$77,901,000
(E) Allowance for FDC		CCM	\$0
(F) Royalty Allowance		CCM	\$0
(G) Preproduction Costs		CCM, 0.02xD	\$1,58,020
(H) Inventory Capital		Included in A	\$0
(I) Initial Catalyst and Chemicals		Included in A	\$0
(J) Plant Scale Up to cover Lost Generation		2903 kW x \$3000 kW	\$8,709,000
(TCI) Total Capital Investment		D+E+G+H+I	\$88,168,020
Direct Annual Costs			
	Natural Gas Reheat Annual Cost	Alstom, Inc.	\$5,827,262
	Annual Reagent (Ammonia Cost)	CCM	\$969,763
	Annual Catalyst Replacement Cost	EKPC	\$1,000,000
	Annual Electrical Cost	CCM	\$1,525,425
	Annual Maintenance Cost	CCM, 0.015xTCI	\$1,322,520
Total Direct Annual Cost			\$10,644,970
(IDAC) Total Indirect Annual Cost		CCM, 7 percent interest for 20 years	\$8,322,437
(TAC) Total Annual Cost		DAC+IDAC	\$18,967,407
NO <sub>x</sub> Removed, Tons (100% Capacity Factor)		0.15 lb/MMBtu to 0.015 lb/MMBtu +160 tons/yr	1,774
Reheat NOX Removed, Tons (100% Capacity Factor)		100 lb/MMscf to 10 lb/mm scf	35
Total NOX Removed, Tons (100% Capacity Factor)		CFB NOX + Reheat NOX	1809
Average Cost Effectiveness, %/ton		TAC/Tons Removed	\$10,485
Incremental Cost Effectiveness, \$/ton		TAC/Tons Removed SNCR to SCR	\$25,033

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### **Environmental Impact of NO<sub>x</sub> Controls**

The reheating of the flue gas associated with SCR would result in additional pollutants from the additional fuel. Another environmental impact would result from the use of ammonia. EKPC indicated that ammonia slip can cause additional impacts by the formation of sulfate salts, which would oxidize to form SO<sub>3</sub> in the presence of the SCR catalyst. The SO<sub>3</sub> would react with moisture in the flue gas or atmosphere to form H<sub>2</sub>SO<sub>4</sub> and would react with the excess ammonia to form condensable sulfates. Since these would be formed downstream of the CFB boiler particulate matter control system, the condensable sulfates would be emitted as condensable particulate matter. Disposal of the spent catalyst is another environmental concern associated with an SCR since heavy metals such as vanadium pentoxide are present and could result in classification of the spent catalyst as a hazardous waste. Finally, on-site storage of ammonia creates a potential for accidents and releases. EKPC acknowledged that collateral environmental impacts are not adverse enough to warrant rejecting SCR on that basis since SCR is a widely-used technology in pulverized coal boilers. However, the environmental impacts of a tail-end SCR on a CFB are greater than the impacts of a hot-side SCR on a PC unit because of the extra fuel required to reheat the flue gas.

EKPC acknowledged that collateral environmental impacts associated with SNCR also exist, but that they are not as great as those associated with SCR. Ammonia or urea storage issues also exist with SNCR. Operation of the SNCR will also result in ammonia slip, however, formation of ammonia slip will occur upstream of the add-on dry scrubber and fabric filter and the hence, the by-products of ammonia slip will be subject to control.

### **Select BACT**

The BACT NO<sub>x</sub> limit is 0.07 lb/MMBtu, which is based on uncontrolled emissions of 0.15 lb/MMBtu, SNCR as a control and 53 percent reduction. Compliance will be demonstrated by a NO<sub>x</sub> CEMS.

In Appendix D, Table D-2 of its application, EKPC provided a list of CFB units, all of which either use SNCR as post combustion NO<sub>x</sub> control, or do not appear to have post combustion control at all. The BACT limit is equal to or less than all units listed. EKPC notes that none of the CFB boilers with BACT limits equivalent to 0.07 lb/MMBtu have commenced operation, so no data is available to assess whether the limit can be met. Refer to Section 5.1.7 for CFB BACT limits during startup and shutdown.

In Table 4-4 of the application, reproduced below, EKPC provided a summary of CFB boiler actual emissions for 2007<sup>16</sup> that were below the proposed BACT limits in this application. EKPC noted that the only unit of comparable size in the list is JEA Northside, and despite the difference in fuel, JEA Northside's achieved emissions are consistent with EKPC's proposed limit. The same applies to AES Thames, although the unit is smaller and the type of coal is not specified.

Table 5-3 CFB Boiler NO<sub>x</sub> Emissions

Source	Size, MW	Fuel	2007 NO <sub>x</sub> Emissions, lb/MMBtu	
			Ozone Season Average	Annual Average
AES Thames	181	Coal	0.066 (Unit A) 0.065 (Unit B)	0.074 (Unit A) 0.072 (Unit B)
AES Warrior Run (Co-Gen)	181	Coal	0.055	0.070
Gilberton (Co-Gen)	2 x 35	Anthracite Culm	0.041 (Unit 1) 0.041 (Unit 2)	0.045 (Unit 1) 0.045 (Unit 2)
Kimberly Clark (Co-Gen)	59	Coal, Anthracite Culm, Pet Coke	0.049	0.060
Northeastern Power	51	Anthracite Culm	0.048	0.050
JEA Northside	2 x 300	Coal, Pet Coke	0.065 (Unit 1A) 0.074 (Unit 2A)	0.067 (Unit 1A) 0.072 (Unit 2A)

EKPC dismissed the other units because they are smaller and combust different fuels, but expanded its explanation in its November 14, 2008 response to the Division's October 14, 2008 Notice of Deficiency. In that response, EKPC noted that differences in fuel nitrogen could result in more fuel nitrogen converted to NO<sub>x</sub>. EKPC also noted that limestone acts as a catalyst for the nitrogen and oxygen reaction, therefore the more limestone added to the CFB to reduce SO<sub>2</sub>, the greater the NO<sub>x</sub> emission rate. Different boiler designs and sizes will have different operating characteristics that affect the amount of primary air and excess air. EKPC notes that anthracite culm has a nitrogen content of 0.5-0.6 percent and a sulfur content of 0.3-0.9 percent while the bituminous coal to be burned at J.K. Smith has a nitrogen content of approximately 1.3 percent and sulfur content of approximately 3 percent. Therefore, units burning different types of coal cannot be expected to achieve the same emission rates.

### 5.1.2 CFB - Sulfur Dioxide (SO<sub>2</sub>) Controls

EKPC identified the following SO<sub>2</sub> control options:

- Use of a lower-sulfur fuel
- Coal washing
- CFB with Limestone Injection
- Wet Flue Gas Desulfurization (WFGD)
- Dry Scrubbing - Ash Reinjection System
- Dry Scrubbing - Dry Sorbent Injection

<sup>16</sup> See <http://camddataandmaps.epa.gov/gdm>

- Dry Scrubbing - Flash Dryer Absorber (FDA) using fresh lime

WFGDs typically use a lime or limestone slurry that is sprayed in the absorber to react with SO<sub>2</sub> in the gas stream. WFGD is typically used by pulverized coal-fired units, but has not been demonstrated on a CFB. However, EKPC acknowledged that in theory, application of a WFGD to a CFB boiler is technically feasible. Since there are no WFGDs on CFBs, the SO<sub>2</sub> removal efficiency can only be estimated. Since 85 percent of the SO<sub>2</sub> would already be removed with limestone injection, the removal efficiency of WFGD on a CFB is likely lower than a pulverized coal unit.

Dry scrubbing systems use a hydrated lime slurry in a reaction vessel where it reacts with SO<sub>2</sub> in the flue gas to form calcium sulfite solids. EKPC indicated that dry systems are the only type of add-on SO<sub>2</sub> controls it is aware of that have been applied to CFB boilers. Types of dry scrubbing systems are ash reinjection, dry sorbent injection, spray dryer absorber, and flash dryer absorber (FDA).

### **Rank Technically Feasible Control Options by Effectiveness**

Table 5-4 Ranking of Technically Feasible CFB Boiler SO<sub>2</sub> Control Technologies

Control Technology	SO <sub>2</sub> Emission Rate tons/year	Percent Reduction
CFB(LI) + WFGD	887	99.1
CFB(LI) + FDA	986	99.0
CFB(LI) + Ash Reinjection	2957	97.0
Low Sulfur (PRB) coal	10452	89.39
CFB(LI)	14783	85.0
Washed coal	21024	78.67
No control	98550	0

Note: EKPC's analysis assumed a 90% capacity factor and a lower SO<sub>2</sub> limit of 0.022 lbs/MMBtu. The above numbers reflect a straight application of the reduction efficiency to a theoretical uncontrolled amount of 98550 tons/year.

EKPC selected CFB with limestone injection and FDA using fresh lime injection. EKPC provided cost analyses comparing its selected option with WFGD, the use of lower sulfur coal, and the use of washed coal. However, as can be seen from the above table, the difference between EKPC's selected option and WFGD is marginal, whereas EKPC's selected option is significantly better than the use of low sulfur coal or washed coal.

**Fuel Switching** - EKPC's analysis resulted in a cost of \$45,920 per ton of SO<sub>2</sub> removed if it switched to washed coal and \$49,874 per ton for Powder River Basin (PRB) coal. However, the analysis filed by EKPC used 0.022 lbs/MMBtu to represent emissions from lower sulfur coals, which was apparently based upon the lowest SO<sub>2</sub> emission limit for a CFB. The analysis below assumes a 3000 MMBtu/hr boiler with limestone injection and FDA and uses the same control efficiency for each scenario.

Table 5-5 Coal Switching Cost Comparison (Controlled)

Coal Characteristic	EKPC Design	Washed Coal	PRB Coal
HHV, Btu/lb	8000	12500	8800
Sulfur Content, percent	3	1	0.35
SO <sub>2</sub> , lb/MMBtu, uncontrolled	7.50	1.60	0.80
SO <sub>2</sub> , lb/MMBtu, 99 percent controlled	0.075	0.016	0.008
Coal usage, tons/year	1,642,500	1,051,200	1,493,182
Cost per ton delivered	\$37.49	\$89.00	\$64.50
Annual Cost	\$61,577,325	\$93,556,800	\$96,310,227
SO <sub>2</sub> , tons/year, uncontrolled	98550	21024	10452
SO <sub>2</sub> , tons/year, controlled	985.5	210.24	105
Difference in Cost	baseline	\$31,979,475	\$34,732,902
Difference in SO <sub>2</sub> emitted	baseline	-775.26	-880.98
Cost per ton of SO <sub>2</sub> removed compared to baseline		\$41,250	\$39,425

At a cost of \$39,425 - \$41,250 per ton of SO<sub>2</sub> removed, the Division concurs that use of lower sulfur coals are not cost-effective.

While EKPC has demonstrated that the use of lower sulfur coal is not cost-effective, the demonstration was based upon an assumption of a control effectiveness of 99 percent. If no control methods had been assumed, the results of the cost comparison would have been substantially different, as follows:

Table 5-6 Coal Switching Cost Comparison (Uncontrolled)

Coal Characteristic	EKPC Design	Washed Coal	PRB Coal
HHV, Btu/lb	8000	12500	8800
Sulfur Content, percent	3	1	0.35
SO <sub>2</sub> , lb/MMBtu, uncontrolled	7.50	1.60	0.80
Coal usage, tons/year	1,642,500	1,051,200	1,493,182
Cost per ton delivered	\$37.49	\$89.00	\$64.50
Annual Cost	\$61,577,325	\$93,556,800	\$96,310,227
SO <sub>2</sub> , tons/year, uncontrolled	98550	21024	10452
Difference in Cost	baseline	\$31,979,475	\$34,732,902
Difference in SO <sub>2</sub> emitted	baseline	-775.26	-880.98
Cost per ton of SO <sub>2</sub> removed compared to baseline	baseline	\$412.50	\$394.25

\$394-\$413 per ton of SO<sub>2</sub> removed is cost-effective, but only in the absence of the SO<sub>2</sub> control methods proposed by EKPC. With the control methods proposed by EKPC, fuel switching is not cost-effective.

Wet FGD vs. FDA

EKPC's proposed SO<sub>2</sub> control system has a 99 percent reduction efficiency, whereas WFGD is 99.1 percent, which is nearly equivalent. EKPC provided a cost analysis, as follows:

Table 5-7 WFGD Cost Analysis

Direct Capital Costs			
	Purchased Equipment Cost (A)	Based upon \$202/kW	\$60,600,000.00
	Instrumentation		\$0.00
	Sales Tax		\$0.00
	Freight		\$0.00
	Direct Installation		\$0.00
Total Direct Capital Cost (B)			\$60,600,000.00
Indirect Capital Costs			
	Engineering		\$0.00
	Construction and Field Expenses	Control Cost Manual, 0.10xB	\$6,060,000.00
	Contractor Fees	Control Cost Manual, 0.10xB	\$6,060,000.00
	Startup	Control Cost Manual, 0.01xB	\$606,000.00
	Performance Test	Control Cost Manual, 0.01xB	\$606,000.00
	Contingencies	Control Cost Manual, 0.03xA	\$1,818,000.00
Total Indirect Capital Cost (B)			\$15,150,000.00
Total Capital Investment		A+B	\$75,750,000.00
Direct Annual Costs			
	Operating Labor, Operator	0.5 hr/shift @30.00 hr	\$5,475.00
	Operating Labor, Supervisor	15 percent of Operator	\$821.25
	Operating Materials	Estimated CUECOST	\$355,875.00
	Wastewater Disposal	Estimated CUECOST	\$1,176,988.00
	Maintenance - Labor	0.5 hr/shift @30.00 hr	\$5,475.00
	Maintenance - Material	100 percent of Maint. Labor	\$5,475.00
	Electricity	Estimated CUECOST	\$1,314,000.00
Total Direct Annual Cost (E)			\$2,864,109.25
Indirect Annual Costs			
	Overhead	60 percent of Labor+Material	\$10,347.75
	Administrative Charges	2 percent of TCI	\$1,515,000.00
	Property Tax	1 percent of TCI	\$757,500.00
	Insurance	1 percent of TCI	\$757,500.00
	Capital Recovery	7 percent interest for 20 years	\$7,150,264.13
Total Indirect Annual Cost			\$10,190,611.88



Total Annual Cost (G)		\$13,054,721.13
Inlet SO <sub>2</sub>		14,782.50
Outlet SO <sub>2</sub>		886.95
SO <sub>2</sub> Removed		13,895.55
Cost per ton removed		\$939.49

Table 5-8 FDA Cost Analysis

Base Unit Capital Cost per MMBtu (U.S. EPA Fact Sheet, Mean)		\$10,000.00
Total Heat Input, MMBtu/hr		3000
Total Capital Cost		\$30,000,000.00
Annual O&M Cost per MMBtu (U.S. EPA Fact Sheet, Mean)		\$800.00
Total Annual O&M Cost		\$2,400,000.00
Annualized Unit Cost per MMBtu (U.S. EPA Fact Sheet, Mean)		\$30,000.00
Capital Recovery Factor	20 years @7 percent	0.0944
Carrying Cost		\$2,832,000.00
Total Annualized Cost		\$5,232,000.00
Inlet SO <sub>2</sub> Emissions, tons/year		14,782.50
Outlet SO <sub>2</sub> emissions		985.50
SO <sub>2</sub> Removed		13,797.00
Cost per ton removed		\$379.21

Both systems are cost-effective at \$379.21 per ton of SO<sub>2</sub> removed for FDA and \$939.49 per ton for WFGD. Although both are cost-effective, WFGD is considerably more expensive on cost per ton of SO<sub>2</sub> removed basis. The incremental difference between the two is:

$$(\$13,054,721.13 - \$5,232,000.00) / (985.50 - 886.95) \text{ tons of SO}_2 \text{ removed} = \$79,378 \text{ per ton of SO}_2 \text{ removed.}$$

That is, the use of WFGD would require an additional cost of \$7.8 million to achieve a reduction of 99 tons of SO<sub>2</sub>. Therefore, the Division concurs that extra cost for WFGD compared to the difference in SO<sub>2</sub> emissions is not cost-effective.

During the public comment period, U.S EPA requested additional analysis with respect to the use of incremental vs. average, or total costs. The use of total costs does not work well in this situation for two reasons. First, it is difficult, if not impossible, to isolate what the cost really is for the pollution control method. With respect to fuel, the fuel is also used to produce electricity. It is possible to isolate the portion of the fuel cost that should be allocated to a pollution control purpose by subtracting the cost of the design fuel from the cost of the cleaner fuels. The difference in cost between the cleaner fuel and the design coal does reflect the additional cost that can be attributed to a pollution control purpose, i.e., the minimum that EKPC would be required to spend to produce electricity is

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the cost of the design coal of \$61,577,325. This amount could be subtracted from the cost of cleaner fuels so that the cost for eliminating or removing pollutants does not contain costs that are unrelated to that purpose. However, this is an incremental calculation and does not reflect average costs. It also needs to be matched to the correct "tons of pollutant" removed.

Care must be taken to ensure that emission reductions achieved from pollution control efficiencies inherent in advanced coal technologies are not incorrectly attributed to a different control option. For example, the CFB boiler plus limestone injection can achieve 85 percent reduction in SO<sub>2</sub> emissions. It would be incorrect to attribute this reduction to another pollution control method, such as fuel switching, SDA, or WFGD. This would penalize advanced coal technologies if the extra cost of the advanced technology is not reflected<sup>17</sup>. One way to reflect the 85 percent reduction inherent in the CFB would be to consider the total cost of the CFB. However, it would not suffice to take the total cost and divide by the tons of pollutants removed. This calculation would exacerbate the problem of including costs that have no bearing on pollution control, but would also include costs that are for the purpose of producing electricity.

An incremental calculation can be used to solve this problem, by comparing total costs of different types of generating units. However, this method would introduce new problems, such as the fact that another type of generating unit may not serve the same business purpose, may not have the capability of using as broad a range of fuel types, may be more or less generating capacity than the original design or may not be capable of phased-construction (i.e., a 600 MW supercritical unit could not be built in phases as the two proposed 300 MW CFBs), and would need to be analyzed from a multi-pollutant perspective, i.e., the CFB boiler is inherently more efficient at reducing acid gases and NO<sub>x</sub> than a pulverized coal unit. It would require significant amounts of data and resources to compute and would need to include differences in risk, generation availability, personnel training, etc., but at the end, it still would not be an average cost.

Second, the results of such an approach could not be compared to results of BACT analyses reviewed by other permitting agencies. The approach used by EKPC in the application appears to be identical to that used by US EPA Region 8 in Deseret and most, if not all, the comparisons listed by Region 8 in its response to comments. If a different approach were taken, the result would be meaningless unless compared to similarly derived numbers from similar sources.

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<sup>17</sup> See for example, New Coal-fired Generation, Costs and Strategies, <http://www.cera.com/aspx/cda/filedisplay/filedisplay.ashx?PK=29043>, which estimates pulverized coal costs at under \$1260/kW and circulating fluidized bed at \$1463/kW. See also <http://media.pennnet.com/documents/Mega+project+pgi+paper.pdf>

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### **Environmental Impact of SO<sub>2</sub> Controls**

EKPC notes that operation of a CFB with WFGD would introduce collateral environmental impacts in the form of a waste stream that requires dewatering before disposal in a landfill, which would necessitate constructing a dewatering pond or waste treatment facility. WFGD also increases the potential for additional particulate matter and sulfuric acid mist.

Operation of dry scrubbing results in similar impacts, except uses less water and does not require dewatering, and has less potential for formation of sulfuric acid mist. If a fabric filter is used to control PM, the lime collects as a filter cake and continues to react with acid gases.

### **Select BACT**

BACT for SO<sub>2</sub> is limestone injection in the boiler and dry scrubbing with fresh lime using FDA, and an emission rate of 0.075 lb/MMBtu.

In Table D-5 of Appendix D of the application, EKPC provided a list of recent BACT determinations for SO<sub>2</sub> from CFB boilers. However, the primary drivers for SO<sub>2</sub> emissions are the sulfur content of the coal and the efficiency of the SO<sub>2</sub> removal system, so comparisons to the BACT determinations from other units is meaningless unless the sulfur content is similar. EKPC's BACT analysis has demonstrated that the use of lower sulfur fuels is not cost-effective.

## **5.1.3 CFB - Particulate Matter (PM) Controls**

### **PM Control Technologies**

EKPC identified the following PM control options:

- Fabric Filtration (FF)
- Electrostatic Precipitation (ESP, dry and wet)

EKPC noted that the controls proposed by EKPC discussed in the context of SO<sub>2</sub> (i.e., limestone injection in the boiler and dry scrubbing) will also reduce PM emissions, providing a co-benefit with the control technology.

### **Rank Technically Feasible Control Options by Effectiveness**

The following table summarizes controlled and uncontrolled particulate matter emissions:

Table 5-9 Particulate Matter Control Options

Control Technology	PM (filterable and condensable) Emission Rate lb/MMBtu	PM (filterable and condensable) Emission Rate tons/year	Percent Reduction
Fabric Filter	0.012	157.68	99.9
ESP	0.015	197.10	99.875
Uncontrolled	12.00	157680.00	0

### **Environmental Impact of PM Controls**

Fabric filter and a dry ESP have similar environmental impacts, whereas a wet ESP would cause a wash-water slurry to be generated. As previously noted, if a fabric filter is used to control PM, the lime collects as a filter cake and continues to react with acid gases.

### **Select BACT**

BACT is a Pulse Jet Fabric Filter and emission limits of 0.009 lb/MMBtu (filterable) and 0.012 lb/MMBtu (total) on a 24-hour average. Compliance shall be demonstrated by PM CEMS.

As the best available control device was selected, no further analysis was required. However, the Division did attempt to discover if fabric filters with higher removal efficiencies than 99.9 percent were available or applicable, and specifically requested information about GE's Max-9™ Electrostatic Fabric Filter<sup>18</sup>, and COHPAC™<sup>19</sup>. In its February 12, 2009 response to a Notice of Deficiency, EKPC explained that both controls are viewed as "polishing" control devices for use in conjunction with a primary control device, and that neither has been demonstrated in practice as a primary PM control option.

### **GE Max-9™**

EKPC noted that the GE's Max-9™ is currently being used as a polishing device on the Allegheny Power R. Paul Smith Generating Unit. EKPC mentioned that the Montana Department of Environmental Quality (MDEQ) rejected the technology in its BACT determination for Highwood Generating Station<sup>20</sup> (HGS). MDEQ noted some technical concerns, primarily as a result of the high particulate loading that will result from the hydrated ash reinjection system. Two potential solutions were developed, one of which was the use of a spray dry absorber. The Division requested information via e-mail from GE on March 18, 2009. No response has been received. Therefore, while GE claims a control efficiency of 99.999 percent on its website, the Division has not been able to verify this claim, nor has GE claimed that its electrostatic fabric filter is

<sup>18</sup> See [http://www.gepower.com/prod\\_serv/products/particulate\\_matter/en/max9/index.htm](http://www.gepower.com/prod_serv/products/particulate_matter/en/max9/index.htm)

<sup>19</sup> See for example <http://www.hamon-researchcottrell.com/COHPACTMandTOXECONTM.asp> and [http://www.pollutionengineering.com/Articles/Cover\\_Story/cc544140bdd68010VgnVCM100000f932a8c0\\_\\_\\_\\_\\_](http://www.pollutionengineering.com/Articles/Cover_Story/cc544140bdd68010VgnVCM100000f932a8c0_____)

<sup>20</sup> See [http://www.deq.mt.gov/AirQuality/ARM\\_Permits/3423-01.pdf](http://www.deq.mt.gov/AirQuality/ARM_Permits/3423-01.pdf), Permit Analysis, page 34.

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applicable or available for the system proposed at J.K. Smith. The MDEQ appears to have reached a similar conclusion, as did U.S. EPA Region 1 in its Draft Permit Number 052-120-MA13<sup>21</sup> for Dominion Energy Brayton Point, LLC, in Somerset, MA. In the accompanying Fact Sheet<sup>22</sup>, page 19, U.S. EPA stated:

*"Electrostatic fabric filter. This is an emerging technology that is not demonstrated in-practice for this application. The use of a combination of electrostatic precipitation and fabric filtration has been tested on a cyclone boiler firing subbituminous coal, and similar technology is being marketed by GE Energy. The lack of operating experience would add significant uncertainty to the air pollution retrofit project, as would the need to coordinate its installation and operation with the dry scrubber. Also, it is not clear that this technology would provide any emissions reduction beyond the proposed case. (footnotes omitted).*

#### COHPAC<sup>TM</sup>

EKPC noted that COHPAC<sup>TM</sup> has been applied to Alabama Power Company's coal-fired E.C. Gaston Units 2 & 3 for use as a retrofit polishing control device to improve performance downstream of ESPs. EKPC indicated that it could find no evidence that COHPAC<sup>TM</sup> has ever been demonstrated as a primary particulate control device. However, there is nothing in the definition of BACT that restricts a BACT determination to one single control device. In fact, EKPC is using both limestone injection and FDA using fresh lime to control SO<sub>2</sub>. Therefore, the Division requested additional analyses to reflect the possibility of using COHPAC<sup>TM</sup> as a polishing control device, to be used in conjunction with the proposed fabric filter.

EKPC supplemented its response on June 26, 2009<sup>23</sup>. EKPC indicated that it has serious technical doubts that COHPAC<sup>TM</sup> would result in additional particulate matter removal and achieve a lower permit limit than what has been proposed as BACT for Smith CFBs. However, based upon cost estimates received in relation to the Cooper Power Station, EKPC estimated that the capital cost for COHPAC<sup>TM</sup> would be approximately \$26,000,000. This results in an annual cost of \$2,454,400 based upon a 20-year life at 7 percent interest. EKPC assumed that an additional 79 tons of PM would be removed (50 percent of PM emissions from Unit 1 after the fabric filter). This resulted in a cost effectiveness of \$31,068 per ton of PM removed (\$2,454,400/79 tons). The Division concurs that COHPAC<sup>TM</sup> used as polishing device is not cost-effective.

BACT for PM, SO<sub>2</sub> and H<sub>2</sub>SO<sub>4</sub> is also BACT for PM<sub>2.5</sub>

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<sup>21</sup> See <http://www.epa.gov/NE/communities/nsemissions.html>

<sup>22</sup> Not dated, but the public comment period was from January 28, 2009 to February 27, 2009.

<sup>23</sup> An attachment was omitted and later filed on July 7, 2009.

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For filterable PM, the chosen fabric filter system is designed to achieve the same level of control (on a mass basis) down to a particle size of 1  $\mu\text{m}$ .<sup>24</sup> The Division is not aware of a filterable PM control device that removes PM less than 1  $\mu\text{m}$  that has not already been evaluated as part of the PM BACT analysis. As such, the fabric filter system selected as BACT for PM is also BACT for PM<sub>2.5</sub>.

Condensable PM is largely comprised of sulfates, acid gases, and organic compounds. Therefore, BACT controls for condensable PM are those that remove emissions controlled through reductions of these pollutants. As such, the most effective control devices for condensable PM are those that work in conjunction with the technologies that provided reductions of those pollutants, such as SO<sub>2</sub> and sulfuric acid mist. The control technology determined to meet BACT for SO<sub>2</sub> and sulfuric acid mist is limestone injection in the CFB, an add-on dry scrubber, and a fabric filter. As the Division is not aware of any additional control technology for condensable PM that was not evaluated in the BACT analysis for SO<sub>2</sub> and sulfuric acid mist, BACT for SO<sub>2</sub> and H<sub>2</sub>SO<sub>4</sub> is BACT for condensable PM<sub>2.5</sub>.

#### **5.1.4 CFB - Carbon Monoxide (CO) Controls**

CO formation in a CFB boiler can be indicative of inefficient combustion, and thus wasted energy. However, increasing temperature tends to decrease CO emissions, but increases NO<sub>x</sub> emissions and vice versa.

##### **CO Control Technologies**

EKPC identified the following CO control options:

- Combustion Controls
- Catalytic Oxidation
- Thermal Oxidation

EKPC proposes combustion controls, which refers to operating a combustion source efficiently. As noted by U.S. EPA in AP-42, 1.1.3.4 (Bituminous and Subbituminous Coal Combustion, Carbon Monoxide):

*"The rate of CO emissions from combustion sources depends on the fuel oxidation efficiency of the source. By controlling the combustion process carefully, CO emissions can be minimized. Thus, if a unit is operated improperly or is not well-maintained, the resulting concentrations of CO (as well as organic compounds) may increase by several orders of magnitude. Smaller boilers, heaters, and furnaces typically emit more CO and organics than larger combustors. This is because smaller units usually have less high-temperature residence time and, therefore, less time to*

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<sup>24</sup> Alstom

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*achieve complete combustion than larger combustors. Combustion modification techniques and equipment used to reduce NO<sub>x</sub> can increase CO emissions if the modification techniques are improperly implemented or if the equipment is improperly designed."*

#### Catalytic Oxidation

In a catalytic oxidation system, CO in the flue gas reacts with a catalyst to form CO<sub>2</sub>. EKPC noted that it is unaware of any PC or CFB boilers that use catalytic oxidation for CO control. It also noted that there are technical issues that preclude successful application of catalytic oxidation with a CFB. Alkaline particulate matter present in the flue gas, along with sulfur, would poison the catalyst, unless the oxidation system was located downstream of the particulate matter collection device. This would require heat exchange equipment and additional fuel to reheat flue gases since the temperature would be below the temperatures necessary for proper catalyst operation.

#### Thermal Oxidation

Thermal oxidation uses high temperature and oxygen to facilitate oxidation of CO to CO<sub>2</sub>, with temperatures in excess of 1500 °F. As the typical maximum furnace temperature in a CFB boiler is in the range 1500 -1600 °F<sup>25</sup>, thermal oxidation is inherent in a CFB boiler.

#### **Rank Technically Feasible Control Options by Effectiveness**

Of the three technologies evaluated, EKPC deemed that only proper combustion control was technically feasible.

#### **Environmental Impacts of CO Controls**

EKPC indicated that there are no significant impacts on economic, energy, or environmental impacts with this control option.

#### **Select BACT**

BACT is the use of proper combustion controls and an emission limit for CO emissions from the CFB boilers of 0.1 lb/MMBtu. Compliance will be demonstrated by CO CEMS.

EKPC provided a listing in Table D-7 in Appendix D of its application which shows recent BACT determinations for CFB boilers for CO. None of the CFB boilers have add-on controls for CO emissions and the emission rate of 0.1 lb/MMBtu is equivalent to the lowest CO BACT limit.

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<sup>25</sup> Multipollutant Emission Control Technology Options for Coal-fired Power Plants" (EPA-600/R-05/034, March 2005. <http://www.epa.gov/airmarkt/resource/docs/multipreort2005.pdf>

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### **5.1.5 CFB - Volatile Organic Compound (VOC) Controls**

EKPC characterized VOC emissions as a function of combustion efficiency, as with CO emissions. EKPC indicated that VOCs form when incomplete combustion of carbon occurs, and are minimized by proper combustion control including maximizing residence time, maintaining adequate combustion temperature, and providing enough excess air to provide adequate oxygen levels and mixing.

#### **VOC Control Technologies**

EKPC identified the same control technologies that were identified for CO control:

- Combustion Controls
- Catalytic Oxidation
- Thermal Oxidation

#### **Rank Technically Feasible Control Options by Effectiveness**

As with CO control technologies, EKPC deemed that only proper combustion control was technically feasible.

#### **Environmental Impact of VOC Controls**

EKPC indicated that there are no significant impacts on economic, energy, or environmental impacts with this control option.

#### **Select BACT**

BACT is the use of proper combustion controls and an emission limit for VOC emissions from the CFB boilers of 0.002 lb/MMBtu. Compliance shall be demonstrated by compliance with the CO limit.

EKPC provided a listing in Table D-8 in Appendix D of its application which shows recent BACT determinations for CFB boilers for VOC emissions. None of the CFB boilers have add-on controls for VOC emissions and the emission limit of 0.002 lb/MMBtu is equivalent to the lowest VOC BACT limit.

### **5.1.6 CFB - Sulfuric Acid Mist (H<sub>2</sub>SO<sub>4</sub>) Controls**

Sulfuric acid mist is formed when sulfur trioxide reacts with water vapor. SO<sub>3</sub> is generated when sulfur in the fuel is oxidized to form SO<sub>2</sub>, of which a small percentage is further oxidized to form SO<sub>3</sub>. Sulfuric acid mist is a component of condensable PM.



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### **H<sub>2</sub>SO<sub>4</sub> Control Technologies**

EKPC identified the following control technologies:

- CFB with limestone injection and fresh lime add-on flash dryer absorber (FDA);
- CFB with limestone injection and wet flue gas desulfurization (WFGD); and
- CFB with limestone injection, dry scrubber and wet electrostatic precipitation (WESP).

All of the above technologies would be combined with a fabric filter which would provide additional control of H<sub>2</sub>SO<sub>4</sub> emissions.

### **Technical Feasibility of Available Control Technologies**

All of the controls are considered technically feasible, although EKPC indicated that it is unaware of any CFB boilers that use WFGD or WESP controls.

### **Rank Technically Feasible Control Options by Effectiveness**

Table 5-10 Sulfuric Acid Mist Control Options

Control Technology	Potential to Emit (tons/year)	Annual Emissions Reduction (from base case) (tons/year)	Percent Reduction
CFB, LI, FDA, FF, WESP	33	624	95%
CFB, LI, FDA, FF	66	591	90%
CFB, LI, FF, WFGD	131	526	80%
CFB, LI, FF	657	base case	50%

The above table lists WESP + FDA, FDA, and WFGD in order of removal efficiency. A CFB with limestone injection is included since it will be used as the basis for comparison.

EKPC provided a cost analysis for a WESP in Appendix D, Table D-9 of the application. EKPC provided three different cost projections for the WESP. Only the lowest cost estimate is shown below:

Table 5-11 Cost Effectiveness of WESP

Item	Cost
Capital Cost per scfm treated	\$20
Gas Flow rate, scfm	500,000
Total Capital Cost	\$10,000,000
Annual O&M cost per scfm	\$5
Annual O&M Cost	\$2,500,000
Capital Recovery Factor (20 years@7%)	0.0944

Annual Capital Cost	\$944,000
Total Annual Cost	\$3,444,000
H <sub>2</sub> SO <sub>4</sub> removed (compared to CFB, LI, FF)	624 tons
Cost per ton removed (compared to CFB, LI, FF)	\$5519
H <sub>2</sub> SO <sub>4</sub> removed (compared to CFB, LI, FDA, FF)	33 tons
Cost per ton removed (compared to CFB, LI, FDA, FF)	\$104,364

The above analysis compares "CFB, LI, FDA, FF, WESP" to "CFB, LI, FF", which results in a difference of 624 tons of sulfuric acid mist removed at a removal cost of \$5519 per ton. While the effect of FDA is reflected in the removal efficiency, the cost of the FDA is not reflected, so the removal cost of \$5519 per ton is under-stated. The analysis also compares "CFB, LI, FDA, FF, WESP" to "CFB, LI, FDA, FF" using the same cost data (i.e., no FDA costs included), but the difference in emissions between the two is only 33 tons of sulfuric acid removed at a cost \$104,364 per ton.

EKPC did not analyze the cost of WFGD without FDA since it provides less control than FDA. However, cost information was provided in the SO<sub>2</sub> cost analysis which shows that the annual cost of a WFGD is \$13,054,721. Assuming that the WFGD would provide an additional 80 percent reduction to the 66 tons per year of H<sub>2</sub>SO<sub>4</sub> remaining after the control train proposed by EKPC, the cost is \$247, 249 per ton of H<sub>2</sub>SO<sub>4</sub> removed (\$13,054,721/(66 x 0.8)), which is not cost-effective.

U.S.EPA commented on the draft permit and EKPC submitted an analysis to show whether it would be cost-effective to switch to lower sulfur coal. However, the analysis includes the entire cost of fuel, which is not appropriate since the primary purpose of the fuel is to generate electricity. The following is based on the analysis EKPC filed, adjusted to reflect the cost of fuel related to electricity production:

	EKPC Design	Washed Coal	PRB
Heating Value, Btu/lb	8000	12500	8800
S content, % by Weight	3	1	0.35
SO <sub>2</sub> Potential, lb/MMBtu	7.5	1.6	0.8
Tons per Year	1642500	1051200	1493182
Cost per Ton Delivered	\$37.49	\$89.00	\$64.50
Total Fuel Cost	\$61,577,325.00	\$93,556,800.00	\$96,310,239.00
Less Fuel Costs to Produce Electricity	\$61,577,325.00	\$61,577,325.00	\$61,577,325.00
FDA Cost	\$5,231,788.00	\$2,831,788.00	\$2,831,788.00
H <sub>2</sub> SO <sub>4</sub> Emissions from Boiler, lb/MMBtu	0.05	0.05	0.05
H <sub>2</sub> SO <sub>4</sub> Emissions from FDA, lb/MMBtu	0.005	0.0024	0.0024
Tons Removed	591.3	625.5	625.5

Cost, \$/ton removed	\$8,847.94	\$55,653.50	\$60,055.48
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It should be noted that the analysis does not recognize the cost of the inherent efficiencies of a CFB plus limestone injection to remove sulfur compounds but yet includes the removal efficiency. However, even without all costs included, the analysis demonstrates that switching to a lower sulfur coal is not cost-effective.

#### **Energy Impact of H<sub>2</sub>SO<sub>4</sub> Controls**

EKPC indicated that application of a WESP would significantly increase energy requirements due to the voltage required to maintain adequate current for removal of H<sub>2</sub>SO<sub>4</sub>, but did not quantify the energy requirement since other economic impacts lead to rejection of WESP. No additional requirements are required to operate the FDA since it is already required for BACT control of SO<sub>2</sub> emissions.

#### **Environmental Impact of H<sub>2</sub>SO<sub>4</sub> Controls**

Operation of a WESP will have collateral environmental impacts since it will create a wash-water slurry. No additional environmental impacts will occur with FDA since it is already required for BACT control of SO<sub>2</sub> emissions.

#### **Select BACT**

EKPC proposed a BACT limit 0.005 lb/MMBtu achieved via the use of a CFB boiler with limestone injection, dry scrubber with fresh lime injection, and a fabric filter.

EKPC provided a list of recent BACT determinations for H<sub>2</sub>SO<sub>4</sub> in Table D-10, Appendix D, of the application. Four sources are listed with H<sub>2</sub>SO<sub>4</sub> limits lower than proposed by EKPC.

Table 5-12 H<sub>2</sub>SO<sub>4</sub> Limits for Other Sources

Source Name	H <sub>2</sub> SO <sub>4</sub> Limit (lbs/MMBtu)
AES Puerto Rico	0.0024
Sevier Power Company	0.0024
Gascoyne	0.0029
Deseret	0.0034

All four use or propose the same control technology as proposed by EKPC. EKPC attributes the difference in emission rates to the sulfur content of the fuel. EKPC noted that AES Puerto Rico and Sevier use coal with a sulfur content of less than 1 percent, Gascoyne uses low sulfur lignite, and that EPA Region 8's

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analysis for Deseret was based upon an uncontrolled SO<sub>2</sub> potential of 1.71 lb/MMBtu. In contrast, EKPC's design fuel has a sulfur content of 3 percent.

EPA Region 8's analysis<sup>26</sup> was based upon 1% of uncontrolled SO<sub>2</sub> converted to SO<sub>3</sub>, 100 percent of SO<sub>3</sub> converted to H<sub>2</sub>SO<sub>4</sub> and a H<sub>2</sub>SO<sub>4</sub> removal efficiency of 87 percent. If similar assumptions are made with respect to SO<sub>2</sub> to SO<sub>3</sub> and SO<sub>3</sub> to H<sub>2</sub>SO<sub>4</sub> conversions, then uncontrolled H<sub>2</sub>SO<sub>4</sub> emissions for CFB1 are 0.1148 lbs/MMBtu (7.50 lbs/MMBtu x 98 lbs H<sub>2</sub>SO<sub>4</sub>/64 lbs SO<sub>2</sub> x 0.01). Based upon these assumptions, a control efficiency of 95.64 percent ((1- 0.005/0.1148) x 100%) would be required to achieve the proposed emission limit of 0.005 lbs H<sub>2</sub>SO<sub>4</sub>/MMBtu, which is greater than the 90 percent reduction proposed by EKPC. Nevertheless, EKPC has committed to achieve 0.005 lbs H<sub>2</sub>SO<sub>4</sub>/MMBtu and the Division concurs that this is BACT for H<sub>2</sub>SO<sub>4</sub>.

### **5.1.7 CFB BACT Limits during Startup, Shutdown or Malfunction**

The permit contains emission limits based upon emission rates used in modeling to demonstrate compliance with National Ambient Air Quality Standards (NAAQS). There are no exemptions for startup, shutdown or malfunction for these emission limits. However, BACT limits are based upon steady-state operating conditions which may or may not be achievable during startup, shutdown or malfunction, as discussed below.

In its application, EKPC noted that during startup and shutdown, emissions exceeding those at standard operating conditions are unavoidable. It noted that natural gas will serve as a startup fuel for the CFB units. A specific startup shutdown plan for the CFBs will be developed prior to operation based upon the manufacturer's operational manual and will include information on cold, warm, and hot starts. EKPC noted that startup and shutdown events do not impact the BACT analysis for the material handling sources, cooling towers, or roadways.

In its November 14, 2008 response to a notification of deficiency, EKPC provided more detailed information on a pollutant-by-pollutant basis. EKPC also provided additional information in its February 12, 2009 response to a notice of deficiency requesting that a startup and shutdown plan be provided. EKPC indicated that despite its experience with CFBs at Spurlock, these units are different because Gilbert starts up on fuel oil, while the Smith units will start up on natural gas. It will not be known how these differences will impact startup and shutdown durations and control device operability until the Smith CFBs are built and the vendor has provided EKPC with an operating manual.

EKPC did provide a description of the typical startup procedure for Gilbert, as follows:

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<sup>26</sup> Deseret Statement of Basis, page 111.

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*"The typical startup of the Gilbert CFB and associated control devices is the following. The startup fuel for Gilbert is fuel oil. The baghouse is placed in normal operation before firing coal. It may not be at maximum effectiveness, however, as there is no buildup of a filter cake on the bags, which assists in the removal of particulate matter from the flue gas. Limestone is injected into the boiler at the same time as the coal to reduce SO emissions. When the boiler reaches approximately 50% load, the conditions are such (e.g., temperature of the flue gas) that the SNCR and FDA can be brought on line. The temperature has to be high enough at the SNCR that the ammonia will react with the NO<sub>x</sub> in the flue gas (approximately 1600°F); otherwise the ammonia will pass through the system unreacted resulting in ammonia slip and little to no decrease in NO<sub>x</sub> emissions. The dry scrubber cannot be brought on line until boiler operation (temperature, coal and limestone) has stabilized. During shutdown, the SNCR and FDA are removed from service at 50% load. The baghouse remains operational until shutdown is complete."*

EKPC also proposed permit language which indicates that during startup and shutdown events, averaged over the duration of the event, emissions would not exceed the mass emission rates used in its air modeling, and that emissions during startup, shutdown, and malfunctions would be included in determining compliance with the tons per year limits for hazardous air pollutants. It defined "startup event" as the period of time beginning with initial use of the burners firing natural gas and ending at the time when the boiler has reached minimum sustainable load firing coal. A "shutdown event" is defined as beginning with the load decreasing from minimum sustainable load and ending when the bed material fluidizing air has been discontinued. EKPC indicated that a CFB boiler startup event typically lasts 72 hours.

The term "minimum sustainable load" is not enforceable without a definition. However, the November 14, 2008 response included more information, as described below.

With respect to NO<sub>x</sub> emissions, EKPC indicated that:

*"NO<sub>x</sub> emissions generated during CFB boiler startup are not controlled via the SNCR system until 45 % load is achieved, based upon the Alstom Power Design and Operation Manual. Operation of the SNCR cannot occur until the proper gas flow and temperature profiles are reached at that load value. Below that level, excess ammonia slip could occur that would lead to fouling of downstream components such as the air heater, FDA and fabric filter. Actual operation of the Spurlock Unit #3 CFB boiler has demonstrated that the NO<sub>x</sub> limit cannot be met during periods of startups and shutdowns for that reason. To illustrate, actual NO<sub>x</sub> CEM data collected at the Spurlock Unit #3 boiler shows NO<sub>x</sub> emissions above*

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*0.09 lb/mmBtu until a loading in the range of 236 MW and 284 MW is achieved. The data collected to date for that unit also shows that the NO<sub>x</sub> mass limit can be achieved below 70% loads, but not during periods of startup and shutdown due to the SNCR operating requirements described above."*

With respect to SO<sub>2</sub> and H<sub>2</sub>SO<sub>4</sub> emissions, EKPC indicated that:

*"SO<sub>2</sub> emissions are controlled by limestone injection in the boiler and by FDA. During startup periods where the boiler loading is below the 45 MW to 200 MW range, the proper fluid bed characteristics promoting effective SO<sub>2</sub> removal in the fluidized bed by the limestone injection cannot be continuously maintained. This increases the SO<sub>2</sub> loading to the FDA such that the limit may not be met. Experience with the Spurlock Unit #3 CFB boiler, which has a SO<sub>2</sub> limit of 0.20 lb/mmBtu, shows that the limit can be met between 45 MW and 200 MW based upon CEM data. With the allowable SO<sub>2</sub> limit for the Smith CFBs considerably lower at 0.075 lb/mmBtu, we believe that a higher MW loading will be necessary to attain during startup before the SO<sub>2</sub> limit for those units can be attained. The operational experience with the Spurlock unit indicates that, once the loading is sufficiently high to stabilize and optimize the fluidized bed characteristics, the loading to downstream controls is reduced due to limestone injection in the fluidized bed and the SO<sub>2</sub> limit therefore can be met. During startup and shutdown periods, however, a point is reached where the bed characteristics are not conducive to optimal SO<sub>2</sub> removal, which is why compliance with the SO<sub>2</sub> limit cannot be continuously maintained during those periods."*

and

*"H<sub>2</sub>SO<sub>4</sub> emissions are controlled in the same manner as SO<sub>2</sub> emissions; thus the discussion provided above describing why the SO limit cannot be maintained continuously during startup and shutdown periods also applies to H<sub>2</sub>SO<sub>4</sub>."*

EKPC provided additional information in its May 22, 2009 filing. Per discussion with Alstom, solid fuel addition cannot occur until the boiler reaches a minimum temperature of 950 °F. When the boiler reaches 40 to 50 percent load, the dry FGD and SNCR controls are brought on-line. However, other variables, such as the temperature of the flue gas which needs to be a minimum of 1600 °F before the ammonia will react with the flue gas.

With respect to PM emissions, EKPC indicated that:

*"Filterable PM is controlled throughout the startup process since the fabric filter is in place and operational. Condensable PM emissions,*

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*which include  $H_2SO_4$  and other acid gases and precursors to condensable emissions such as  $NO_x$ , are not controlled at an optimal level until sufficient load is attained such that control train components are operational as designed. Please refer to the discussions on  $NO_x$  and  $SO_2$  emissions during startup and shutdown, which illustrate the startup conditions where the SNCR cannot be operated and where the fluidized bed characteristics are not optimal. The reasons given for the inability to continuously maintain compliance with those limits during periods of startup and shutdown also apply to the condensable PM emissions.”*

With respect to CO and VOC emissions, EKPC indicated that:

*“CO and VOC emissions are optimized via combustion controls, which cannot be maintained at stable levels when the boiler is in startup or shutdown modes where the loads are variable trending up or down. Maintaining the temperature and air flow profiles at their design levels, along with the proper fluidized bed characteristics necessary for optimal combustion, is difficult to achieve for any steady time frame while the boiler load is ramping up or ramping down during startup or shutdown. While no CEM data is available for VOC, direct experience with the Spurlock Unit # 3 CFB boiler shows CO emissions during startup are not maintained below the limit of 0.10 lb/mmBtu until a loading of 150 MW is achieved. We would expect VOC emissions to be subject to the same variability as CO during periods of startup and shutdown since emissions of both pollutants are minimized by the same type of control procedures.”*

The preceding explanation supports an exemption during startup and shutdown from the emissions per unit heat input emissions limits (lbs/MMBtu). As EKPC has acknowledged, no exemptions are required for emissions per unit time limits (lbs/hour) when averaged over averaging periods in the permit, which are based upon the NAAQS averaging periods.

A 72-hour start up period has not been supported by information from the equipment manufacturer. However, EKPC has advised that it will not receive precise information from the manufacturer until much later in the construction process. Therefore, the initial permit will limit startup to 24 hours, with an exception if necessary to avoid equipment damage or unsafe, non-standard practices.

A "Startup event" shall be considered to be the setting in operation of a boiler for any purpose after demonstration of initial compliance, beginning with the introduction of coal in the boiler and ending when the generator has sustained 45 percent (135 MW) of its nominal rating (300 MW) for at least one hour. Startup shall not exceed 24 hours, except to avoid equipment damage, unsafe operation, or deviation from established original equipment manufacture (OEM) procedure.

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A "Shutdown" event shall be considered as cessation of operation of a boiler beginning with the generator going below 135 MW, curtailment of the fuel supply to the boiler, and ending after fuel flow has ceased. A shutdown event shall not exceed 10 hours.

## **5.2 Material Handling and Roadways**

### **5.2.1 Coal Handling**

Coal will be delivered via truck and rail. The coal will be conveyed from the unloading areas via enclosed conveying equipment to two new coal piles. PM emissions due to loading to the piles will be controlled by dust suppression or by the use of a lowering well to minimize the distance of the material drop.

An enclosed conveying system will transfer coal from the coal pile to a new coal crusher house. The coal crusher house will provide processing and crushing of the coal to the desired specification for combustion. PM emissions will be controlled by completely enclosing the crushing equipment and ducting the emissions to a fabric filter.

Enclosed conveyors will transport the coal from the crusher house to storage silos located inside the main boiler building. PM emissions will be controlled by a fabric filter.

### **5.2.2 Lime and Limestone Handling**

Lime and uncrushed limestone will be delivered to the site by truck and stored. Wet suppression will control dust generated by limestone unloading. After unloading, limestone will be conveyed to an underground conveyor system for transport to the boiler building, where it will be crushed and stored in silos. A fabric filter on the silo exhaust will be used to control PM. Pneumatically conveyed limestone from the silo will then be fed to the boiler for control of SO<sub>2</sub> emissions.

Lime for the dry scrubber system will be conveyed via enclosed conveyors and stored in silos, also controlled by a fabric filter.

### **5.2.3 Ash Handling**

Bed ash is cooled and collected into an enclosed conveyor that is routed to a storage silo. Fly ash from the baghouse and boiler economizer is collected using a pressurized pneumatic system that is also routed to a storage silo. The ash will then be transported off-site for disposal. Conveyors and truck loading will be enclosed and fabric filters will be used to control PM emissions from the silos.



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#### **5.2.4 Haul Roads**

Paved roadways will be used for the haul trucks. Dust suppressants or mitigation, including sweeping will be employed if necessary to further reduce emissions.

#### **5.2.5 BACT Analysis**

EKPC identified control options for PM emissions from material handling sources based upon a review of the EPA RBLC database, EPA technical reports, technical journals, recently issued PSD permits, and CFB boiler permit applications. Control options for PM emissions from material handling operations are listed as follows:

- Enclosed Conveyors and Transfer Points
- Lowering Wells or Dust Suppression for Storage Piles
- Enclosed Crushing Operations with Fabric Filtration
- Enclosed Storage Silos with Fabric Filtration
- Dust Suppression
- Paved Roadways

EKPC indicated that all of the above options are technically feasible. EKPC indicated that these are the control options employed throughout the industry as BACT for material handling and thus represent the most effective control options for these sources of PM emissions.

EKPC provided a listing of recent BACT determinations for emissions from coal handling operations in Table D-11 in Appendix D of the application. A similar listing for lime and limestone handling activities are in Table D-12. The tables show that the BACT listings for other coal handling sources use the same control measures proposed by EKPC, with the exception of compaction as a control measure for coal stockpiles. Coal pile compaction is routinely performed as a fire safety measure, but is also useful as a means to control fugitive emissions, so the Division has added coal pile compaction as BACT for coal piles.

EKPC indicated that where EKPC's proposed emission limits may be greater than one or more limits listed in Table D-11 in Appendix D of its application, the insignificant particulate impacts on air quality should justify the choice of the PM emissions limitations without the need for alternate control technology considerations<sup>27</sup>.

This is incorrect. The definition of "significant" is codified in 401 KAR 51:001/51:001E, Section 1. The threshold for PM is 25 tons per year and PM<sub>10</sub> is 15 tons per year, which is exceeded by the proposed project. While the majority

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<sup>27</sup> See application, page 4-4.

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of the particulate matter emissions are from the CFB boilers, BACT still applies to all particulate matter emissions from the proposed project, regardless of the level of contribution to total emissions from an individual emissions unit. As noted in Section 5, the definition of BACT in 401 KAR 51:002, Section 1(25) includes consideration of "economic impacts and other costs".

The Division requested that EKPC demonstrate that all fabric filters associated with material handling activities are BACT<sup>28</sup>, particularly since the emission factors expressed in gr/dscf varied among the emission units. It was not clear why fabric filters with the lowest emission rates should not be considered BACT for all emission units.

EKPC's response dated February 12, 2009 revised the BACT for material handling fabric filters to be consistent with U.S. EPA's proposed revisions of 40 CFR 60, Subpart Y, Standards of Performance for Coal Preparation Plants<sup>29</sup> and 40 CFR 60, Subpart OOO, Standards of Performance for Nonmetallic Mineral Processing Plants<sup>30</sup>. The revised emission rates varied between 0.01 to 0.005 gr/dscf. EKPC concluded that BACT for fabric filters with an airflow greater than 5000 dscfm is 0.005 gr/dscf outlet grain loading and 0.01 gr/dscf outlet grain loading for fabric filters with an air flow less than 5000 dscfm. EKPC noted that these revisions were consistent with the proposed Subpart Y requirements and were less than the proposed Subpart OOO requirement of 0.014 gr/dscf.

In its response dated June 24, 2009, with respect to 5000 dscfm being the criteria for selecting between 0.005 gr/dscf and 0.01 gr/dscf outlet grain loading, EKPC referred to its previous response described above. However, that response did not contain an explanation. EKPC identified portions of the proposed changes to Subpart Y and Subpart OOO that address control equipment performance, as well as noted that U.S. EPA had issued a supplemental proposal on May 27, 2009 for Subpart Y which proposes a higher PM limit than initially proposed. EKPC cited U.S. EPA's conclusion that 0.010 gr/dscf is achievable *"for all sizes of affected facilities"*<sup>31</sup>. However, the preceding sentence states: *"(b)ased on the performance test data, we have conclude that although 0.011 g/dscm (0.0050 gr/dscf) has been show to be achievable, due to the limited data set, we are not convinced that such a limit would be achievable on a long-term basis for all affected facilities across the country"*. This illustrates the difference between the criteria used to establish emission limits applicable *"for all sizes of affected facilities"* and the case-by-case analysis required for BACT. Therefore, in the absence of any reason why 0.005 gr/dscf is not achievable or not cost-effective, the Division concludes that 0.005 gr/dscf is BACT for all material handling fabric filters.

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<sup>28</sup> See Notice of Deficiency dated January 9, 2009, Item 3.

<sup>29</sup> See 73 Federal Register, 22901, dated April 28, 2008.

<sup>30</sup> See 73 Federal Register, 21559, dated April 22, 2008.

<sup>31</sup> See 74 Federal Register, 25304, 25313-314, dated May 27, 2009.

BACT for PM is also BACT for PM<sub>2.5</sub>

The control technologies identified for PM emissions from material handling are the same control technologies that would be identified for PM<sub>2.5</sub> emissions from material handling. As the Division is not aware of a control technology that would reduce PM<sub>2.5</sub> emissions more effectively than the chosen technologies, the control technologies selected as BACT for PM<sub>10</sub> would also represent BACT for PM<sub>2.5</sub>.

### 5.3 Cooling Towers

Each CFB will have its own cooling tower, each with a feed rate of approximately 146,000 gallons per minute. PM emissions occur when a portion of the cooling water carries over and drifts out of the tower, with the PM resulting from solids in the cooling water.

Drift eliminators are the only known control technology applicable to wet cooling towers. Therefore, EKPC will use drift eliminators to control PM emissions with a maximum drift rate of 0.0005 percent.

Table D-14 in Appendix of the application lists BACT determinations for cooling towers. EKPC has selected the lowest known maximum drift rate of 0.0005 percent.

BACT for PM is also BACT for PM<sub>2.5</sub>

As drift eliminators are the only known control technology applicable to wet cooling towers, BACT for emissions from cooling towers also represents BACT for PM<sub>2.5</sub> emissions from cooling towers.

## 6. AIR QUALITY IMPACT ANALYSIS

### 6.1 Modeling Background

Pursuant to 401 KAR 51:017, Section 11, an application for a PSD permit shall contain an analysis of ambient air quality impacts. As part of the PSD regulations, JK Smith is required to demonstrate compliance with ambient air quality standards using dispersion modeling. Air quality impact analyses were presented in this application using the American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) for Class II impacts within 50 kilometers (km) of JK Smith and California Puff Model (CALPUFF) for Class I impacts within 300 km of JK Smith. The air dispersion modeling analyses described in the application were conducted in accordance with 40 CFR Part 51, Appendix W, which contains the federal *Guideline on Air Quality Models (Revised November 9, 2005)*.

The Class II area modeling analyses were completed in three principle steps: the Significance Analysis (comparison of modeled impacts against the Significant Impact

Levels (SILs) and monitoring *de minimis* concentrations), the Kentucky and National Ambient Air Quality Standards (NAAQS) Analysis, and the PSD Increment Analysis.

The application for the proposed modifications contained Class II area air dispersion modeling analyses for criteria pollutants to determine the maximum ambient concentrations attributable to emissions from the facility and other nearby regional sources in comparison with:

- (1) The significant impact levels (SIL) found in 40 CFR 51.165(b)(2);
- (2) The monitoring *de minimis* concentrations found in 401 KAR 51:017;
- (3) The PSD Increments found in 401 KAR 51:017;
- (4) The Kentucky Ambient Air Quality Standards (AAQS) found in 401 KAR 53:010; and
- (5) The National Ambient Air Quality Standards (NAAQS) found in 40 CFR part 50.

## 6.2 Modeling Analysis

### Class II Modeling

Table 6-1 shows the Class II Significant Impact Levels (SILs), Kentucky and National AAQS, and the Class II PSD increments with which the facility must comply.

Table 6-1 U.S. EPA PSD Pollutant Reference Table -Class II Significance Levels, Ambient Air Quality Standards and PSD Increments

Pollutant	Averaging Period	Significant Impact Levels ( $\mu\text{g}/\text{m}^3$ ) <sup>a</sup>	National AAQS ( $\mu\text{g}/\text{m}^3$ ) <sup>a</sup>	Kentucky AAQS ( $\mu\text{g}/\text{m}^3$ ) <sup>a</sup>	PSD Increments ( $\mu\text{g}/\text{m}^3$ ) <sup>a</sup>
Nitrogen Dioxide	Annual	1	100	100	25
Sulfur Dioxide	Annual	1	80	80	20
	24-hour	5	365 <sup>b</sup>	365 <sup>b</sup>	91
	3-hour	25	1,300 <sup>b</sup>	1,300 <sup>b</sup>	512
Carbon Monoxide	8-hour	500	10,000 <sup>b</sup>	10,000 <sup>b</sup>	NA
	1-hour	2,000	40,000 <sup>b</sup>	40,000 <sup>b</sup>	NA
PM <sub>10</sub> <sup>c</sup>	Annual	1	Revoked	50	17
	24-hour	5	150 <sup>b</sup>	150 <sup>b</sup>	30
PM <sub>2.5</sub>	Annual	NA	15	NA	NA
	24-hour	NA	35	NA	NA
Lead	Quarterly	NA	1.5	1.5	NA
	Rolling 3-Month	NA	0.15	NA	NA
Ozone	8-hour	NA	150	NA	NA
	1-hour	NA	235 <sup>b,d</sup>	235 <sup>e</sup>	NA
Hydrogen Sulfide	1-hour	NA	NA	14	NA
Gaseous Fluorides (expressed as hydrogen fluoride)	Annual	NA	NA	400	NA
	Monthly	NA	NA	0.82 <sup>b</sup>	NA
	Weekly	NA	NA	1.64 <sup>b</sup>	NA
	24-hour	NA	NA	800, 2.86 <sup>b,f</sup>	NA

Pollutant	Averaging Period	Significant Impact Levels ( $\mu\text{g}/\text{m}^3$ ) <sup>a</sup>	National AAQS ( $\mu\text{g}/\text{m}^3$ ) <sup>a</sup>	Kentucky AAQS ( $\mu\text{g}/\text{m}^3$ ) <sup>a</sup>	PSD Increments ( $\mu\text{g}/\text{m}^3$ ) <sup>a</sup>
	12-hour	NA	NA	3.68 <sup>b</sup>	NA

<sup>a</sup> micrograms per cubic meter

<sup>b</sup> Not to be exceeded more than once per calendar year;

<sup>c</sup> Particulate matter with aerodynamic diameter less than or equal to 10 microns

<sup>d</sup> Only applies to areas out of compliance with 8-hour ozone standard

<sup>e</sup> The standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above 0.12 ppm (235  $\mu\text{g}/\text{m}^3$ ) is equal to or less than one (1), as determined by Appendix H of 40 CFR 50.

<sup>f</sup> Primary standard is 800  $\mu\text{g}/\text{m}^3$ ; secondary standard is 2.86  $\mu\text{g}/\text{m}^3$

NA Not Applicable

Table 6-2 summarizes the modeled impacts from the significant impact analysis and compares them with applicable SILs. The modeling results presented are from two meteorological datasets. Since CO concentrations fall below the SIL, no further analysis is needed. In addition, ozone precursors did not indicate an exceedance of the design value for ozone of 0.075 ppm. However, PM<sub>10</sub>, NO<sub>x</sub>, and SO<sub>2</sub> exceed the SIL thus require a cumulative modeling analysis to demonstrate compliance with AAQS and also the PSD increment.

Table 6-2 Significant Impact Modeling Results

Pollutant	Average	Maximum Impact ( $\mu\text{g}/\text{m}^3$ )	Significant Impact Level ( $\mu\text{g}/\text{m}^3$ )
CO	1-HR	46.65	2000
	8-HR	25.98	500
PM <sub>10</sub>	24-HR	27.33	5
	ANNUAL	6.67	1
SO <sub>2</sub>	3-HR	21.86	25
	24-HR	7.86	5
	ANNUAL	1.43	1
NO <sub>x</sub>	ANNUAL	1.4	1

Table 3 summarizes the modeled impact results for comparison to the PSD increment. J.K. Smith's proposed emissions will not cause a violation of any PSD increment.

Table 6-3 PSD Increment Modeling Results

Pollutant	Average	Maximum Impact ( $\mu\text{g}/\text{m}^3$ )	Maximum Allowable Increment ( $\mu\text{g}/\text{m}^3$ )	Percent of Increment Consumed percent
PM <sub>10</sub>	24-HR	25.24 <sup>a</sup>	30	84.1
	ANNUAL	7.33 <sup>b</sup>	17	43.1
SO <sub>2</sub>	24-HR	18.64 <sup>a</sup>	91	20.5
	ANNUAL	3.03 <sup>b</sup>	20	15.2

NO <sub>x</sub>	ANNUAL	2.18 <sup>b</sup>	25	8.7
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<sup>a</sup>Highest-second high impacts for 24-hour averages

<sup>b</sup>The annual average is the maximum concentration in accordance with National AAQS

Table 6-4 summarizes the modeled impact results for comparison to the NAAQS. As demonstrated, J.K. Smith's proposed emissions will not cause a violation of any ambient air quality standards.

Table 6-4 AAQS Modeling Results

Pollutant	Average	Maximum Impact (µg/m <sup>3</sup> )	Background Concentration (µg/m <sup>3</sup> )	Total Ambient Impact (µg/m <sup>3</sup> )	NAAQS <sup>c</sup> (µg/m <sup>3</sup> )
PM <sub>10</sub>	24-HR	29.85 <sup>a</sup>	36	67.85	150
	ANNUAL	7.87 <sup>b</sup>	21	28.87	50
SO <sub>2</sub>	24-HR	52.29 <sup>a</sup>	94.32	146.61	365
	ANNUAL	7.66 <sup>b</sup>	13.1	20.76	80
NO <sub>x</sub>	ANNUAL	5.42 <sup>b</sup>	22.56	27.98	100

<sup>a</sup>Highest-second high impacts for 24-hour averages

<sup>b</sup>The annual average is the maximum concentration in accordance with National AAQS

<sup>c</sup>The KY Primary AAQS is either equivalent or more restrictive than the National AAQS

Table 6-5 summarizes the modeled impact results for gaseous fluorides in comparison to the Kentucky AAQS. As demonstrated, J.K. Smith's proposed emissions of gaseous fluorides will not cause a violation of any Kentucky AAQS.

Table 6-5 Gaseous Fluoride Modeling Results

Pollutant	Average	Maximum Impact (µg/m <sup>3</sup> )	Kentucky AAQS Primary Standard (µg/m <sup>3</sup> )	Kentucky AAQS Secondary Standard (µg/m <sup>3</sup> )
Gaseous Fluoride HF	12-HR	0.00372	N/A	3.68
	24-HR	0.00253	800	2.86
	ANNUAL	0.00046	400	N/A
	MONTH	0.00071	N/A	0.082

Table 6-6 summarizes the impact results for ozone in comparison to the stayed ozone NAAQS based upon CAMx modeling as demonstrated in *Modeling and Analysis to Support GA SIP Development (December 2006 Update)*. J.K. Smith's proposed emissions of ozone precursors will not cause a violation of the ozone design value of 0.075 ppm using the Fayette Co. monitor (AQS-ID 21-067-0012).

Table 6-6 Ozone Results

Pollutant	Average	Maximum Contribution to Background (ppm)	Maximum Concentration including Background (ppm)	Ozone Design Value (ppm)
Ozone	8-HR 4 <sup>th</sup> high	0.00047	0.073	0.075

### **Class I Modeling**

Class I modeling was reviewed in Revision 2 of the permit, which involved the construction and operation of two new combustion turbines, Emission Units 9 and 10. The following has been copied from the Revised Statement of Basis dated August 28, 2008.

Class I areas are defined in the Clean Air Act as national parks over 6,000 acres and wilderness areas and memorial parks over 5,000 acres. The Clean Air Act gave Federal Land Managers (FLMs) the affirmative responsibility to protect the air quality related values (including visibility) of any Class I lands and to consider, in consultation with permitting authorities, whether a proposed major emitting facility will have an adverse impact on such values. Accordingly, the FLMs formed the Federal Land Managers' Air Quality Related Values Work Group (FLAG) to develop a consistent approach for the FLMs to evaluate air pollution effects on their resources. In accordance with National Park Service (NPS) and FLM guidance, Class I areas within 300 km of the source were included in the analysis. EKPC identified 5 Class I areas:

- Mammoth Cave National Park - 185 km
- Great Smoky Mountains National Park - 246 km
- Joyce Kilmer-Slickrock Wilderness - 281 km
- Linville Gorge Wilderness Area - 290 km
- Shining Rock Wilderness Area - 293 km

### **Class I Modeling Methodology**

EKPC submitted a modeling protocol for review by the Division, the EPA, the National Park Service, and the U.S. Forest Service, which was submitted to the Division on June 22, 2006.

In accordance with EPA Guidance<sup>32</sup>, EKPC conducted the Class I area analysis using the CALPUFF system.

Impacts on visibility were evaluated by determining the maximum 24-hour change in light extinction, or  $\Delta b_{ext}$ , in each Class I area of concern. Deposition impacts are evaluated by calculating the total sulfate and total nitrate deposition rate from modeling source emissions to determine the wet and dry flux concentrations.

<sup>32</sup> The EPA Guideline on Air Quality Models (GAQM) promulgated under 40 CFR 51, Appendix W, specifies the CALPUFF modeling system for conducting Class I analyses on areas greater than 50 km from the source.

Table 6-7 Modeled Emission Rates

Source	Species	Emission Rate (lb/hr)	Notes
CFB1	SO <sub>2</sub>	225.0	Based upon 0.075 lb/MMBtu
	PM <sub>10</sub> <sup>Note 1</sup>	36.0	Based upon 0.012 lb/MMBtu total PM
	NO <sub>x</sub>	210.0	Based upon 0.07 lb/MMBtu <sup>Note2</sup>
	SO <sub>4</sub>	38.5	NPS Spreadsheet Calcs + H2SO4
	SOA	5.87	NPS Spreadsheet Calcs
	PMC	3.67	NPS
	PMF	2.84	NPS
	EC	0.11	NPS
CFB2	SO <sub>2</sub>	229.6	Based upon 0.075 lb/MMBtu
	PM <sub>10</sub>	36.7	Based upon 0.012 lb/MMBtu total PM
	NO <sub>x</sub>	214.3	Based upon 0.07 lb/MMBtu <sup>Note2</sup>
	SO <sub>4</sub>	39.3	NPS Spreadsheet Calcs + H2SO4
	SOA	5.98	NPS Spreadsheet Calcs
	PMC	3.75	NPS
	PMF	2.9	NPS
	EC	0.11	NPS
CT <sub>s</sub> <sup>Note 3</sup>	SO <sub>2</sub>	0.1	Total SO <sub>2</sub>
	PM <sub>10</sub>	10	Total PM
	NO <sub>x</sub>	16.8	Based upon 5 ppm
	SO <sub>4</sub>	0.05	NPS Spreadsheet Calcs
	SOA	3.95	NPS Spreadsheet Calcs
	EC	6.00	NPS Spreadsheet Calcs

Note 1: Only included for increment modeling; PM emissions were speciated for deposition and visibility modeling.

Note 2: Based on 0.07 lb/MMBtu 30-day average and corresponding mass emission rate of 210 lbs/hr for the 24-hour average for CFB Unit 1 and 214.3 lbs/hr for CFB Unit 2.

Note 3: Emissions from a single CT

### Class I Results

None of the SILs were exceeded in any of the five areas, summarized as follows:

Table 6-8 Class I Modeling Results - Increment Consumption

Modeled Year	Pollutant	Averaging Time	SIL (ug/m <sup>3</sup> )	Mammoth Cave (ug/m <sup>3</sup> )	Smoky Mountains (ug/m <sup>3</sup> )	Joyce-Kilmer Slickrock (ug/m <sup>3</sup> )	Shining Rock (ug/m <sup>3</sup> )	Linville Gorge (ug/m <sup>3</sup> )
2001	PM <sub>10</sub>	24-hour	0.3	0.0327	.0276	0.0091	0.0085	0.0086
		Annual	0.2	0.0010	0.0008	0.0005	0.0004	0.0004
	NO <sub>x</sub>	Annual	0.1	0.0019	0.0009	0.0004	0.0014	0.0016
	SO <sub>2</sub>	3-hour	1	0.5055	0.4267	0.1601	0.1112	0.0748
		24-hour	0.2	0.1367	0.1060	0.0325	0.0251	0.0232
		Annual	0.1	0.0035	0.0026	0.0015	0.0012	0.0014
2002	PM <sub>10</sub>	24-hour	0.3	0.0457	0.0207	0.0112	0.0076	0.0073
		Annual	0.2	0.0017	0.0008	0.0005	0.0003	0.0003
	NO <sub>x</sub>	Annual	0.1	0.0043	0.0010	0.0004	0.0014	0.0014
	SO <sub>2</sub>	3-hour	1	0.5233	0.2565	0.1450	0.1268	0.0858
		24-hour	0.2	0.1877	0.0733	0.0478	0.0267	0.0332
		Annual	0.1	0.0069	0.0025	0.0015	0.0012	0.0012



Modeled Year	Pollutant	Averaging Time	SIL (ug/m <sup>3</sup> )	Mammoth Cave (ug/m <sup>3</sup> )	Smoky Mountains (ug/m <sup>3</sup> )	Joyce-Kilmer Slickrock (ug/m <sup>3</sup> )	Shining Rock (ug/m <sup>3</sup> )	Linville Gorge (ug/m <sup>3</sup> )
2003	PM <sub>10</sub>	24-hour	0.3	0.0451	0.0361	0.0283	0.0099	0.0149
		Annual	0.2	0.0013	0.0008	0.0006	0.0002	0.0004
	NO <sub>x</sub>	Annual	0.1	0.0024	0.0010	0.0025	0.0010	0.0019
	SO <sub>2</sub>	3-hour	1	0.5068	0.4033	0.2523	0.1348	0.1111
		24-hour	0.2	0.1453	0.1221	0.1012	0.0325	0.0439
		Annual	0.1	0.0047	0.0026	0.0021	0.0008	0.0016

With respect to total sulfur and total nitrogen deposition, none of the predicted deposition values equal or exceed the threshold of 0.01 kg/ha/yr. This threshold was developed by the National Park Service (NPS) and U.S. Fish and Wildlife Service (FWS) as the point that would trigger a management concern, not necessarily the amount that constitutes an adverse impact<sup>33</sup>. The following table summarizes these impacts:

Table 6-9 Class I Modeling Results - Sulfur and Nitrogen Depositions

Modeled Year	Deposited Material	Mammoth Cave (kg/ha/yr)	Smoky Mountains (kg/ha/yr)	Joyce-Kilmer Slickrock (kg/ha/yr)	Shining Rock (kg/ha/yr)	Linville Gorge (kg/ha/yr)
2001	Total N	0.0013	0.0007	0.0004	0.0005	0.0006
	Total S	0.0044	0.0025	0.0014	0.0012	0.0016
2002	Total N	0.0026	0.0008	0.0005	0.0005	0.0006
	Total S	0.0086	0.0028	0.0021	0.0014	0.0011
2003	Total N	0.00144	0.0007	0.0007	0.0004	0.0008
	Total S	0.00484	0.0026	0.0018	0.0011	0.0020

### Class I Visibility

40 CFR 51 Subpart P, Protection of Visibility, sets forth requirements addressing visibility impairment, which is defined as "any humanly perceptible change in visibility (light extinction, visual range, contrast, coloration) from that which would have existed under natural conditions." Per FLM Guidance<sup>34</sup>, there are three different visibility impact thresholds: levels of concern, analysis thresholds, and decision thresholds. The levels of concern are visibility impact levels that would alert the FLM to a need for closer scrutiny. The analysis thresholds parallel these levels of concern in that if visibility impacts approach the levels of concern, the FLM would need to see further analyses to make an informed judgment about those impacts. The decision thresholds correspond to the visibility impacts, below which the FLM is not likely to object to an increase in visibility impairing pollutants.

Visibility parameters relate to the effects of discrete plumes and aggregation of discrete plumes. The visibility impairment from sources with 50 kilometers of a view is usually calculated using contrast and color difference, where visibility of sources greater than 50

<sup>33</sup> See <http://www2.nature.nps.gov/air/Pubs/pdf/flag/nsDATGuidance.pdf>

<sup>34</sup> Federal Land Managers' Air Quality Related Values Workgroup (FLAG), Phase I Report (December 2000), <http://www2.nature.nps.gov/air/permits/flag/flagDoc/index.cfm>

kilometers, is usually calculated using the change in light extinction, or  $\Delta b_{\text{ext}}$ . Per FLM Guidance, the FLMs are concerned about situations where a change in extinction from a new source is greater than 5% as compared against natural conditions. Changes in extinction greater than 10% are generally considered unacceptable by the FLMs and will likely raise objections to further pollutant loading without mitigation.

The following tables represent EKPC's results of its CALPUFF modeling. The first table is based upon the use of Method 2 for background light extinction. Joyce-Kilmer Slickrock, Shining Rock, and Linville Gorge had no days in which  $\Delta b_{\text{ext}}$  exceeded 5%, whereas Mammoth Cave had one day greater than 5% in 2002 and the Smokey Mountains had one day in both 2002 and 2003. No days exceed 10%  $\Delta b_{\text{ext}}$ .

Table 6-10 Class I modeling Results - Visibility Modeling Using Method 2

Class I Area	Modeled Year	Maximum Predicted $\Delta b_{\text{ext}}$	Number of Days With $\Delta b_{\text{ext}} > 5\%$	Number of Days With $\Delta b_{\text{ext}} > 10$
Mammoth Cave	2001	3.11	0	0
	2002	3.53	0	0
	2003	5.15	1	0
Smoky Mountains	2001	3.59	0	0
	2002	5.18	1	0
	2003	7.92	1	0
Joyce-Kilmer Slickrock	2001	2.2	0	0
	2002	3.25	0	0
	2003	2.34	0	0
Shining Rock	2001	1.46	0	0
	2002	1.5	0	0
	2003	0.92	0	0
Linville Gorge	2001	0.57	0	0
	2002	0.52	0	0
	2003	1.47	0	0

EKPC elected to run the analysis again using Method 6. Method 2 applies an hourly  $f(\text{RH})$  adjustment to observed and modeled sulfate and nitrate and allows relative humidity to be capped at 95%. Method 6 applies a monthly  $f(\text{RH})$  adjustment factor to observed and modeled sulfate and nitrate. The results are as follows:

Table 6-11 Class I Modeling Results - Visibility Modeling Using Method 6

Class I Area	Modeled Year	Maximum Predicted $\Delta b_{\text{ext}}$	Number of Days With $\Delta b_{\text{ext}} > 5\%$	Number of Days With $\Delta b_{\text{ext}} > 10$
Mammoth Cave	2003	6.22	1	0
Smoky Mountains	2002	3.63	0	0
Smoky Mountains	2003	6.56	1	0

### 6.3 Summary

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J.K. Smith has demonstrated compliance to the Kentucky Division of Air Quality's satisfaction that emissions from the J.K. Smith Generating Station will not cause a violation of any ambient air quality standards or PSD increment for the Class I and Class II areas.

## **7. ADDITIONAL IMPACTS ANALYSIS**

Pursuant to 401 KAR 51:017, the owner or operator shall provide an analysis of the impairment to visibility, soils, and vegetation that will occur as a result of the source or modification; and general commercial, residential, industrial and other growth associated with the source or modification. The owner or operator shall not be required to provide an analysis of the impact on vegetation having no significant commercial or recreational value. The owner or operator shall provide an analysis of the air quality impact projected for the area as a result of the general commercial, residential, industrial and other growth associated with the source or modification.

### **7.1 Soils and Vegetation Impacts Analysis**

Neither the primary nor secondary<sup>35</sup> NAAQS were exceeded; therefore, no impairment to soils and vegetation is expected to occur as result of the proposed project

### **7.2 Construction Impacts and Secondary Growth**

EKPC has indicated that the project is expected to impact employment in the area. The building phase for the CTs and CFB1 will last approximately three years, and at its peak, employment is forecasted to reach 800 employees. Projected full time employment is estimated at 10 for the CTs, 60 for CFB1, and 25 for CFB2.

Projected related air quality impacts during construction are expected to include fugitive dust emissions and vehicle emissions. EKPC will take reasonable precautions to minimize fugitive emissions and will prevent their transport beyond the property boundary.

### **7.3 Class II Visibility**

EKPC was required to conduct visibility impacts on two sensitive Class II areas, Cave Run Lake and Red River Gorge. EKPC used the EPA VISCREEN model for evaluation of plume visual impacts. The model estimates color difference parameter ( $\Delta E$ ) and the plume contrast using three wavelengths of light for plumes against a sky background and against a terrain background. A Level 1 analysis was first performed, which is based upon default, worst case type assumptions. If no adverse visual impact is predicted, no further action is required. If a threshold value of 2.0 for  $\Delta E$  and 0.05 for green contrast is exceeded, then a more refined analysis is performed using data that is more

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<sup>35</sup> As noted on EPA's webpage on NAAQS, <http://epa.gov/air/criteria.html>, the purpose of secondary standards are to "set limits to protect public welfare, including protection against decreased visibility, damage to animals, crops, vegetation, and buildings.

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representative of actual conditions. The Level 1 analysis resulted in a maximum  $\Delta E$  of 3.391 and maximum contrast of 0.013 for the Red River Gorge and a maximum  $\Delta E$  of 1.376 and maximum contrast of 0.003 for Cave Run Lake. Therefore, further analysis of the Red River Gorge was required, but not Cave Run Lake.

With the Level 2 analysis, meteorological data was used that was more representative of the site and refinements were made to the emissions data ( $\text{NO}_x$  was multiplied by 0.75 to account for the portion of  $\text{NO}_x$  that actually comprises  $\text{NO}_2$ ). The Level 2 analysis resulted in a maximum  $\Delta E$  of 0.197 and maximum contrast of 0.001 for the Red River Gorge, both of which are below the screening threshold, and hence will not result in adverse visibility impacts in the Red River Gorge.

## Comparison of Application Emission Factors to AP-42

Pollutant	EKPC EF lbs/MMBtu	AP-42			Highest EF lbs/MMBtu	Potential Emissions tons/year
		Tables 1.1-13 to 16		Table 1.1-18		
		lbs/ton	lbs/MMBtu*	lbs/MMBtu		
1, 1, 2-trichloroethane	4.70E-06	2.00E-05	7.69E-07		4.70E-06	0.061758
2-chloroacetophenone	2.90E-07	7.00E-06	2.69E-07		2.90E-07	0.003811
2,4-dinitrotoulene	1.50E-08	2.80E-07	1.08E-08		1.50E-08	0.000197
Acetaldehyde	6.75E-06	5.70E-04	2.19E-05		2.19E-05	0.288069
Acetophenone	6.80E-07	1.50E-05	5.77E-07		6.80E-07	0.008935
Acrolein	3.25E-06	2.94E-04	1.13E-05		1.13E-05	0.148583
Benzene	2.50E-06	1.30E-03	5.00E-05		5.00E-05	0.657000
Benzyl chloride	6.00E-09	7.00E-04	2.69E-05		2.69E-05	0.353769
Bis(2-ethylhexyl) phthalate	4.10E-06	7.30E-05	2.81E-06		4.10E-06	0.053874
Bromoform	6.60E-06	3.90E-05	1.50E-06		6.60E-06	0.086724
Carbon disulfide	4.30E-06	1.30E-04	5.00E-06		5.00E-06	0.065700
Carbon tetrachloride	3.25E-06				3.25E-06	0.042705
Chlorobenzene	3.18E-06	2.20E-05	8.46E-07		3.18E-06	0.041785
Chloroform	3.20E-06	5.90E-05	2.27E-06		3.20E-06	0.042048
Cumene	2.90E-07	5.30E-06	2.04E-07		2.90E-07	0.003811
Dibutyl phthalate	2.80E-06				2.80E-06	0.036792
Ethyl benzene	4.10E-07	9.40E-05	3.62E-06		3.62E-06	0.047506
Ethyl chloride	2.40E-06	4.20E-05	1.62E-06		2.40E-06	0.031536
Methyl chloroform	3.42E-06				3.42E-06	0.044939
Ethylene dichloride	3.10E-06	4.00E-05	1.54E-06		3.10E-06	0.040734
Formaldehyde	4.00E-06	2.40E-04	9.23E-06		9.23E-06	0.121292
Hexane	8.30E-07	6.70E-05	2.58E-06		2.58E-06	0.033861
Hexachlorobenzene	8.00E-08				8.00E-08	0.001051
Isophorone	2.40E-05	5.80E-04	2.23E-05		2.40E-05	0.315360
Methyl bromide	8.90E-07	1.60E-04	6.15E-06		6.15E-06	0.080862
Methyl chloride	5.90E-06	5.30E-04	2.04E-05		2.04E-05	0.267854
Methyl iodine	4.00E-07				4.00E-07	0.005256
Methyl isobutyl ketone	4.90E-06				4.90E-06	0.064386
Methyl methacrylate	1.10E-06	2.00E-05	7.69E-07		1.10E-06	0.014454
Methyl tert-butyl ether	1.40E-06	3.50E-05	1.35E-06		1.40E-06	0.018396
Methylene chloride	1.30E-05	2.90E-04	1.12E-05		1.30E-05	0.170820
n-nitrosodimethylamine	6.80E-07				6.80E-07	0.008935
Naphthalene	7.70E-07	1.30E-05	5.00E-07		7.70E-07	0.010118
m,p-cresol	6.75E-07				6.75E-07	0.008870
o-cresol	1.70E-06				1.70E-06	0.022338
p-cresol	9.50E-07				9.50E-07	0.012483
Perylene	7.50E-08				7.50E-08	0.000986
Pentachlorophenol	8.00E-09				8.00E-09	0.000105
Phenol	6.10E-06	1.60E-05	6.15E-07		6.10E-06	0.080154
Phthalic anhydride	4.90E-06				4.90E-06	0.064386
Propionaldehyde	1.04E-05	3.80E-04	1.46E-05		1.46E-05	0.192046

**Statement of Basis**  
**Permit No. V-05-070 R3**

**Appendix A**

Pollutant	EKPC EF lbs/MMBtu	AP-42			Highest EF lbs/MMBtu	Potential Emissions tons/year
		Tables 1.1-13 to 16 lbs/ton	lbs/MMBtu*	Table 1.1-18 lbs/MMBtu		
Quinoline	5.30E-08				5.30E-08	0.000696
Styrene	3.10E-06	2.50E-05	9.62E-07		3.10E-06	0.040734
Tetrachloroethylene	3.10E-06	4.30E-05	1.65E-06		3.10E-06	0.040734
Toluene	3.60E-06	2.40E-04	9.23E-06		9.23E-06	0.121292
Trans-1,3 dichloropropene	4.70E-06				4.70E-06	0.061758
Trichloroethylene	3.10E-06				3.10E-06	0.040734
Vinyl acetate	4.20E-07	7.60E-06	2.92E-07		4.20E-07	0.005519
Vinylidene chloride	9.70E-06				9.70E-06	0.127458
Xylenes	4.65E-06	3.70E-05	1.42E-06		4.65E-06	0.061101
o-xylenes	8.10E-07				8.10E-07	0.010643
m,p-xylenes	1.45E-06				1.45E-06	0.019053
2,3,7,8-tetrachlorodi-benzo-p-dioxin	1.50E-12				1.50E-12	0.000000
1,2,3,7,8-tetrachlorodi-benzo-p-dioxin	2.80E-12				2.80E-12	0.000000
1,2,3,4,7,8-hexachlorodi-benzo-p-dioxin	5.90E-12				5.90E-12	0.000000
1,2,3,6,7,8-hexachlorodi-benzo-p-dioxin	6.60E-12				6.60E-12	0.000000
1,2,3,7,8,9-hexachlorodi-benzo-p-dioxin	7.90E-12				7.90E-12	0.000000
1,2,3,4,6,7,8-heptachlorodi-benzo-p-dioxin	4.20E-12				4.20E-12	0.000000
Heptachlorodi-benzo-p-dioxin	7.60E-11				7.60E-11	0.000001
Hexachlorodi-benzo-p-dioxin	2.70E-11				2.70E-11	0.000000
Octachlorodi-benzo-p-dioxin	3.60E-11				3.60E-11	0.000000
Pentachlorodi-benzo-p-dioxin	8.00E-12				8.00E-12	0.000000
Tetrachlorodi-benzo-p-dioxin	8.80E-12				8.80E-12	0.000000
2,3,7,8-tetrachlorodi-benzofuran	4.40E-12				4.40E-12	0.000000
1,2,3,7,8-pentachlorodi-benzofuran	4.60E-12				4.60E-12	0.000000
2,3,4,7,8-pentachlorodi-benzofuran	4.80E-12				4.80E-12	0.000000
1,2,3,4,7,8-hexachlorodi-benzofuran	7.90E-12				7.90E-12	0.000000
1,2,3,6,7,8-hexachlorodi-benzofuran	4.00E-12				4.00E-12	0.000000
1,2,3,7,8,9-hexachlorodi-benzofuran	6.80E-12				6.80E-12	0.000000
2,3,4,6,7,8-hexachlorodi-benzofuran	1.20E-12				1.20E-12	0.000000
1,2,3,4,6,7,8-heptachlorodi-benzofuran	5.70E-12				5.70E-12	0.000000
1,2,3,4,7,8,9-heptachlorodi-benzofuran	1.80E-11				1.80E-11	0.000000
Heptachlorodi-benzofuran	1.90E-11				1.90E-11	0.000000
Hexachlorodi-benzofuran	2.10E-11				2.10E-11	0.000000
Octachlorodi-benzofuran	1.70E-12				1.70E-12	0.000000
Pentachlorodi-benzofuran	1.20E-11				1.20E-11	0.000000
Tetrachlorodi-benzofurna	1.10E-11				1.10E-11	0.000000
1-methylnaphthalene	1.00E-08				1.00E-08	0.000131
2-chloronaphthalene	4.00E-08				4.00E-08	0.000526
2-methylnaphthalene	3.20E-08				3.20E-08	0.000420
Acenaphthene	1.30E-08	5.10E-07	1.96E-08		1.96E-08	0.000258
Acenaphthylene	4.00E-09	2.50E-07	9.62E-09		9.62E-09	0.000126
Anthracene	4.00E-09	2.10E-07	8.08E-09		8.08E-09	0.000106

Pollutant	EKPC EF lbs/MMBtu	AP-42			Highest EF lbs/MMBtu	Potential Emissions tons/year
		Tables 1.1-13 to 16 lbs/ton	lbs/MMBtu*	Table 1.1-18 lbs/MMBtu		
Benz(a)anthracene	2.00E-09	8.00E-08	3.08E-09		3.08E-09	0.000040
Benzo(a)pyrene	1.00E-09	3.80E-08	1.46E-09		1.46E-09	0.000019
Benzo(e)pyrene	1.00E-09				1.00E-09	0.000013
Benzo(b)fluoranthene	8.00E-09	1.10E-07	4.23E-09		8.00E-09	0.000105
Benzo(b+k)fluoranthene	4.00E-09	1.10E-07	4.23E-09		4.23E-09	0.000056
Benzo-(k)fluoroanthene	4.00E-09	1.10E-07	4.23E-09		4.23E-09	0.000056
Benzo-(g,h,i.)perylene	2.00E-09	2.70E-08	1.04E-09		2.00E-09	0.000026
Biphenyl	1.80E-07	1.70E-06	6.54E-08		1.80E-07	0.002365
Chrysene	3.00E-09	1.00E-07	3.85E-09		3.85E-09	0.000051
Dibenzo(a,h)anthracene	1.00E-09				1.00E-09	0.000013
Fluoranthene	1.60E-08	7.10E-07	2.73E-08		2.73E-08	0.000359
Fluorene	1.30E-08	9.10E-07	3.50E-08		3.50E-08	0.000460
Indeno(1,2,3-c,d)pyrene	3.00E-09	6.10E-08	2.35E-09		3.00E-09	0.000039
Phenanthrene	3.20E-08	2.70E-06	1.04E-07		1.04E-07	0.001365
Pyrene	1.20E-08	3.30E-07	1.27E-08		1.27E-08	0.000167
Antimony	5.25E-07			1.13E-06	1.13E-06	0.014783
Arsenic	4.47E-06			2.56E-05	2.56E-05	0.336713
Beryllium	2.22E-07			1.31E-06	1.31E-06	0.017246
Hydrogen chloride	3.19E-04				3.19E-04	4.191660
Hydrogen fluoride	4.70E-05				4.70E-05	0.617540
Cadmium	4.90E-06			3.19E-06	4.90E-06	0.064386
Chromium	1.87E-05			1.63E-05	1.87E-05	0.246309
Cobalt	9.00E-07			6.25E-06	6.25E-06	0.082125
Lead	3.86E-06			2.63E-05	2.63E-05	0.344925
Manganese	5.99E-06			3.06E-05	3.06E-05	0.402413
Mercury	1.93E-05			5.19E-06	1.93E-05	0.252945
Nickel	1.50E-05			1.75E-05	1.75E-05	0.229950
Selenium	4.17E-06			8.13E-05	8.13E-05	1.067625
Not listed above:						
5-Methyl chrysene		2.20E-08	8.46E-10		8.46E-10	0.000011
Cyanide		2.50E-03	9.62E-05		9.62E-05	1.263462
Dimethyl sulfate		4.80E-05	1.85E-06		1.85E-06	0.024258
Ethylene dibromide		1.20E-06	4.62E-08		4.62E-08	0.000606
Methyl hydrazine		1.70E-04	6.54E-06		6.54E-06	0.085915
chromium vi				4.94E-06	4.94E-06	0.064879
Total						13.595568

\*Conversion based on a heating value of 26 MMBtu/ton  
per Section 1.1.5 of AP-42

### HAPS Sorted in Descending Order

Pollutant	Potential Emissions (tons/year)
Hydrogen chloride	4.191660
Cyanide	1.263462
Selenium	1.067625
Benzene	0.657000
Hydrogen fluoride	0.617540
Manganese	0.402413
Benzyl chloride	0.353769
Lead	0.344925
Arsenic	0.336713
Isophorone	0.315360
Acetaldehyde	0.288069
Methyl chloride	0.267854
Mercury	0.252945
Chromium	0.246309
Nickel	0.229950
Propionaldehyde	0.192046
Methylene chloride	0.170820
Acrolein	0.148583
Vinylidene chloride	0.127458
Formaldehyde	0.121292
Toluene	0.121292
Bromoform	0.086724
Methyl hydrazine	0.085915
Cobalt	0.082125
Methyl bromide	0.080862
Phenol	0.080154
Carbon disulfide	0.065700
chromium vi	0.064879
Methyl isobutyl ketone	0.064386
Phthalic anhydride	0.064386
Cadmium	0.064386
1, 1, 2-trichloroethane	0.061758
Trans-1,3 dichloropropene	0.061758
Xylenes	0.061101
Bis(2-ethylhexyl) phthalate	0.053874
Ethyl benzene	0.047506
Methyl chloroform	0.044939
Carbon tetrachloride	0.042705
Chloroform	0.042048
Chlorobenzene	0.041785



Pollutant	Potential Emissions (tons/year)
Ethylene dichloride	0.040734
Styrene	0.040734
Tetrachloroethylene	0.040734
Trichloroethylene	0.040734
Dibutyl phthalate	0.036792
Hexane	0.033861
Ethyl chloride	0.031536
Dimethyl sulfate	0.024258
o-cresol	0.022338
m,p-xylenes	0.019053
Methyl tert-butyl ether	0.018396
Beryllium	0.017246
Antimony	0.014783
Methyl methacrylate	0.014454
p-cresol	0.012483
o-xylenes	0.010643
Naphthalene	0.010118
Acetophenone	0.008935
n-nitrosodimethylamine	0.008935
m,p-cresol	0.008870
Vinyl acetate	0.005519
Methyl iodine	0.005256
2-chloroacetophenone	0.003811
Cumene	0.003811
Biphenyl	0.002365
Phenanthrene	0.001365
Hexachlorobenzene	0.001051
Perylene	0.000986
Quinoline	0.000696
Ethylene dibromide	0.000606
2-chloronaphthalene	0.000526
Fluorene	0.000460
2-methylnaphthalene	0.000420
Fluoranthene	0.000359
Acenaphthene	0.000258
2,4-dinitrotoulene	0.000197
Pyrene	0.000167
1-methylnaphthalene	0.000131
Acenaphthylene	0.000126
Anthracene	0.000106
Pentachlorophenol	0.000105
Benzo(b)fluoranthene	0.000105
Benzo(b+k)fluoranthene	0.000056
Benzo-(k)fluoroanthene	0.000056

Pollutant	Potential Emissions (tons/year)
Chrysene	0.000051
Benz(a)anthracene	0.000040
Indeno(1,2,3-c,d)pyrene	0.000039
Benzo-(g,h,i,)perylene	0.000026
Benzo(a)pyrene	0.000019
Benzo(e)pyrene	0.000013
Dibenzo(a,h)anthracene	0.000013
5-Methyl chrysene	0.000011
Heptachlorodi-benzo-p-dioxin	0.000001
Octachlorodi-benzo-p-dioxin	0.000000
Hexachlorodi-benzo-p-dioxin	0.000000
Hexachlorodi-benzofuran	0.000000
Heptachlorodi-benzofuran	0.000000
1,2,3,4,7,8,9-heptachlorodi-benzofuran	0.000000
Pentachlorodi-benzofuran	0.000000
Tetrachlorodi-benzofuran	0.000000
Tetrachlorodi-benzo-p-dioxin	0.000000
Pentachlorodi-benzo-p-dioxin	0.000000
1,2,3,7,8,9-hexachlorodi-benzo-p-dioxin	0.000000
1,2,3,4,7,8-hexachlorodi-benzofuran	0.000000
1,2,3,7,8,9-hexachlorodi-benzofuran	0.000000
1,2,3,6,7,8-hexachlorodi-benzo-p-dioxin	0.000000
1,2,3,4,7,8-hexachlorodi-benzo-p-dioxin	0.000000
1,2,3,4,6,7,8-heptachlorodi-benzofuran	0.000000
2,3,4,7,8-pentachlorodi-benzofuran	0.000000
1,2,3,7,8-pentachlorodi-benzofuran	0.000000
2,3,7,8-tetrachlorodi-benzofuran	0.000000
1,2,3,4,6,7,8-heptachlorodi-benzo-p-dioxin	0.000000
1,2,3,6,7,8-hexachlorodi-benzofuran	0.000000
1,2,3,7,8-tetrachlorodi-benzo-p-dioxin	0.000000
Octachlorodi-benzofuran	0.000000
2,3,7,8-tetrachlorodi-benzo-p-dioxin	0.000000
2,3,4,6,7,8-hexachlorodi-benzofuran	0.000000